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CLEAN COAL TECHNOLOGY DEVELOPMENT AND STRATEGIES FOR ACID RAIN CONTROL

HEARINGS

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

NINETY-NINTH CONGRESS

SECOND SESSION

ON

CLEAN COAL TECHNOLOGY DEVELOPMENT AND STRATEGIES FOR ACID RAIN CONTROL

JUNE 9 AND 10, 1986

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CLEAN COAL TECHNOLOGY DEVELOPMENT AND STRATEGIES FOR ACID RAIN CONTROL

MONDAY, JUNE 9, 1986

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 10:05 a.m., in room SD-366, Dirksen Senate Office Building, Hon. James A. McClure, chairman, presiding.

Present: Senators McClure, Domenici, Warner, Murkowski, Ford, Melcher, and Rockefeller.

Also present: Richard D. Grundy, director of oversight and investigations; Jeffrey Arnold, professional staff member; Elizabeth Moler, James T. Bruce, and Patricia Beneke, counsels for the minority.

OPENING STATEMENT OF HON. JAMES A. McCLURE, A U.S. SENATOR FROM THE STATE OF IDAHO

The CHAIRMAN. The committee will come to order.

Today we convene 2 days of oversight hearings on the relationship between the development of clean coal technologies and strategies for acid rain control.

Acid rain and other forms of air pollution transported over long distances comprise complex phenomena with important political, economic, social, and environmental implications. The potential socioeconomic cost of such long-range transport stimulated President Reagan to endorse the January 1986 Joint Envoys Report on Acid Rain—which I request be included in the record at the end of my opening remarks.

Few disagree that the popular term "acid rain" describes a very complex phenomenon of atmospheric chemistry that is very poorly understood. Similarly, few would disagree that we cannot be assured that the strategies being proposed for acid rain mitigation will achieve the intended environmental benefits, even though accompanied by significant economic costs. Uncertainty thus exists regarding what actions would be taken by a prudent person to achieve the intended goals for the mitigation of acid precipitation.

Environmental benefits are to be achieved from the control of acid rain, but how they are achieved has significantly different social and economic consequences for different parts of America. In many instances the consumers paying for the controls do not receive the benefits.

When the Congress enacted the Clean Air Act, it was expected that there would be a constant improvement in air quality as older facilities were replaced by new ones subject to new source performance standards. However, as indicated by earlier hearings of the committee, this has not occurred for a variety of reasons. Life extension of utility boilers is a more common practice, but such new construction must eventually be built. Acid rain controls are but one of the many concerns facing the electric utility industry. Further investments in existing plants do not relieve them of the eventual need for new construction, hopefully utilizing clean coal technologies.

An acid rain control strategy that further encourages extension of the life of existing electric utility plants may have considerably different long-term energy and economic consequences than a controlled strategy that relies on the construction of new clean coal technologies, but these consequences are not understood.

If a control strategy based on life extension is indeed in the national interest, then a Clean Coal Technology Development Program that emphasizes new construction runs the risk of demonstrating control technologies which no one will be in a position to use.

As stated in the May 15 Congressional Record notice of hearing, the primary objectives of these hearings are:

First, to review what is entailed in the recent United States-Canadian agreement on acid rain;

Second, to review the types of proposals received under the DOE clean coal technology solicitation;

Third, to examine the potential regulatory and other barriers to the development and deployment of clean coal technologies;

Fourth, to review the comparative costs of sulfur oxide and nitrogen oxide controls with current and future clean coal technologies; and

Finally, to review from the perspective of State regulatory bodies and industry the economic and environmental implications of proposed acid rain controls.

But I must emphasize that the general purpose of these hearings is to provide from a macroperspective a review of the relationship between timetables for implementation of the DOE clean coal technology program and those strategies and timetables being proposed for mitigation of acid rain. It is important that we understand that interrelationship.

These hearings are being held because of the concern of this Senator and others for the apparent dichotomy between the development of acid rain control policy and the development of new clean coal technologies. This dichotomy exists for various political, institutional, and technical reasons. Nevertheless, it is in the national interest that the interrelationship between energy and environmental policies be appropriately reflected in any strategies for the mitigation of acid rain.

[The report "Joint Report of the Special Envoys on Acid Rain" submitted by the chairman follows:]

JOINT REPORT OF THE SPECIAL ENVOYS ON ACID RAIN

Drew Lewis
United States of America

William Davis
Canada

January 1986

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I. BACKGROUND

The United States and Canada share a long tradition of mutual friendship and co-operation and share similar points of view on many international issues. We are also each other's largest trading partners, an economic relationship involving billions of dollars' worth of manufactured goods, services, and raw materials. These common bonds between close neighbors and good friends are valued aspects of a shared history on which both countries continue to build.

Over the past two decades, scientists and government officials on both sides of our border have become aware of the serious environmental problems associated with airborne pollutants transported over long distances. The most serious of these problems is acid rain. Although we do not understand all the mechanisms of the formation and transport of acid rain or the full extent of its effects, it is clear that those causes and effects are shared by both countries. Air emissions from sources in both the United States and Canada have increased significantly the deposition of sulfates and nitrates on both U.S. and Canadian ecosystems.

On March 17 and 18, 1985, Prime Minister Brian Mulroney and President Ronald Reagan met in Quebec City to discuss a wide range of bilateral issues such as mutual defense, trade, and the environment. That meeting, later referred to as the "Shamrock Summit," was viewed as a unique opportunity to reinforce ties between the two countries. At that meeting acid rain was recognized by both leaders as a serious concern affecting bilateral relations.

Noting the 75-year history of environmental co-operation between the two countries, the President and the Prime Minister expressed their determination to address current U.S.-Canadian environmental issues, including acid rain, in the same spirit of responsibility and co-operation. Consequently, each agreed to appoint a personal Special Envoy to examine the acid rain issue and report back before their next meeting, scheduled for the spring of 1986. For the first time, Special Envoys appointed by both the U.S. and Canadian governments were to review jointly this serious environmental issue affecting both nations. These special appointments emphasized the need for both countries to work together to resolve a shared transboundary problem.

II. U.S.-CANADIAN ENVIRONMENTAL RELATIONS

While of relatively recent origin, Canadian and U.S. efforts to address problems associated with the long-range transboundary transport of airborne pollutants have occurred within the context of a 75-year tradition of environmental co-operation.

The cornerstone of our bilateral environmental relaitonship is Article IV of the *Boundary Waters Treaty* of 1909, wherein each country agreed not to pollute boundary waters to the injury of health or property in the other country. With the Article IV obligation as a foundation, both countries have built a long tradition of generally successful resolution of a wide variety of transboundary environmental problems, both through the International Joint Commission and on a government-to-government basis. Notable among recent achievements have been the *Great Lakes Water Quality Agreements* of 1972 and 1978, which were ambitious joint efforts to improve Great Lakes water quality throught the adoption and gradual refinement of water quality objectives, both general and specific.

Bilateral efforts to protect transboundary air quality date to the Trail Smelter case in 1949. An arbitration panel established to resolve an air pollution problem caused by the Trail Smelter held that "no State has the right to use or permit the use of its territory in such a manner as to cause injury by fumes in or to the territory of another."

Both Canada and the United States also subscribe to Principle 21 of the 1972 *Stockholm Declaration* which, like Article IV and the Trail Smelter case, provided that States have the responsibility "to ensure that activities within their jurisdiction or control do not cause damage to the environment of other States." Additionally, both countries are parties to the 1979 *Convention on Long-Range Transboundary Air Pollution*, under which signatory States from the Economic Commission for Europe (ECE) expressed a determination to "endeavour to limit and, as far as possible, gradually reduce and prevent air pollution including long-range transboundary air pollution."

Acid rain became recognized as an important bilateral environmental problem in the mid-1970s. The first response of both the U.S. and Canadian governments was to establish in 1978 the Bilateral Research Consultation Group to report on the extent and significance of long-range air pollution problems, including acid rain, with special reference to the overall transboundary pollutant flux.

In 1978, the U.S. Congress passed a formal resolution which called upon the President to "make every effort to negotiate a co-operative agreement with the Government of Canada aimed at preserving the mutual airshed of the United States and Canada." Subsequent to this Resolution, representatives from the two governments mapped out a comprehensive strategy designed to lead in a step by step manner to the goal of a bilateral air quality agreement.

On July 16, 1979, both governments issued a *Joint Statement on Transboundary Air Quality* in which they recognized "the importance and urgency" of transboundary air pollution problems, including acid rain, and pledged to work toward "a co-operative bilateral agreement on air quality" in accordance with certain declared principles and practices. Then, on August 5, 1980, a *Memorandum of Intent* (MOI) was signed, in which both governments explicitly recognized the seriousness of the acid rain problem, and committed themselves to work toward a bilateral air quality agreement "as soon as possible." They further agreed to set up a framework for negotiations. Five bilateral working groups were established to provide expert scientific and technical advice to a Co-ordinating Committee, which was to commence formal negotiations not later than June 1, 1981. Pending conclusion of the agreement, both countries agreed to take appropriate interim actions to "promote the vigorous enforcement of existing laws and regulations . . . in a way which is responsive to the problems of transboundary air pollution."

Although a bilateral air quality agreement was not reached, considerable scientific and diplomatic activity took place subsequent to the MOI. For example, bilateral co-operation continued at the level of co-ordination of scientific research. The executive committee of the U.S. National Acid Precipitation Assessment Program (MAPAP) and the Canadian Research and Monitoring Co-ordination Committee have met annually to exchange information, co-ordinate research, and plan co-operative research activities.

The new initiative resulting from the appointment of the Special Envoys significantly furthers the development of a bilateral response to the North American transboundary air pollution problem. The foundations of that response — the *Joint Statement* and the *Memorandum of Intent* — are already in place. A precedent for that response already exists in the *Great Lakes Water Quality Agreements*. What remains is to borrow from that precedent and build upon those foundations a bilateral accord which will jointly address a common problem in the best tradition of U.S.-Canadian environmental relations.

III. THE SPECIAL ENVOYS

On March 17, 1985, President Reagan appointed Drew Lewis, former Secretary of Transportation, to be U.S. Special Envoy on Acid Rain. Prime Minister Mulroney appointed William Davis, former Premier of Ontario. As Special Envoys, our overall responsibility was very clear: we were to assess the international environmental problems associated with transboundary air pollution, and then recommend actions that would help solve them. Even though domestic acid rain is causing widespread concern in both countries, we were committed to working together to address the problem expressly in terms of its international implications.

In order to support this overall responsibility, we were assigned four specific tasks:

1. to pursue consultation on laws and regulations related to pollutants thought to be linked to acid rain;
2. to enhance co-operation in research efforts, including research on clean fuel technology and smelter controls;
3. to pursue means to increase exchange of relevant scientific information; and
4. to identify efforts to improve the U.S. and Canadian environments.

Soon after our appointments, we began an intensive educational effort designed to provide us with a quick but comprehensive overview of this scientifically complex issue. We were afforded access to the foremost authorities on acid rain, and all principal research findings were made available to us. We reviewed data and conclusions and attended a variety of briefings and presentations. To date, we or our staffs have met, either individually or jointly, with key people from government, industry, labor, academia, and the environmental and scientific communities. The individuals and groups we have met include:

- senior officials in Washington and Ottawa;
- U.S. cabinet members and Canadian cabinet ministers;
- U.S. and Canadian environmental officials;
- Members of Congress and Parliament;
- U.S. governors and Canadian premiers;
- scientists and researchers in the United States and Canada;
- industrial leaders, notably those in the utility, coal mining, and ore smelting sectors;

- representatives of organized labor, unions, and concerned groups of citizens; and
- leaders of environmental organizations.

We have also made site visits to a power plant in western Pennsylvania and to a research facility in Muskoka, Canada. We have responded to requests for dozens of statements and interviews; we have corresponded with various interest groups and private citizens in both countries.

In short, since March 1985 we have immersed ourselves in the scientific, economic, and political aspects of the acid rain issue. We have not emerged from that experience as experts on all aspects of acid rain. However, we have gained a clearer understanding of the major issues involved and are now in a position to make recommendations for appropriate future activities.

The two most important things we learned can be stated simply:

- **Acid rain is a serious environmental problem in both the United States and Canada**. Acidic emissions transported through the atmosphere undoubtedly are contributing to the acidification of sensitive areas in both countries. The potential for long-term socio-economic costs is high.
- **Acid rain is a serious transboundary problem**. Air pollutants emitted by sources in both countries cross their mutual border, thus causing a diplomatic as well as an environmental problem.

At the same time, we also learned something very important about potential solutions to the acid rain problem:

- **At the present time, there are only a limited number of potential avenues for achieving major reductions in acidic air emissions**, and they all carry high socio-economic costs.

Thus acid rain is not only an environmental and technical problem, but also one with far-ranging socio-economic and political implications which are different in the United States and Canada.

IV. U.S.-CANADIAN EXPERIENCE WITH ACID RAIN

There is no question that acid rain is an environmental problem shared by both the United States and Canada. Emission sources in both countries contribute to acid deposition in both countries.

Yet the shared nature of this problem should not obscure the fact that each of the two countries contributes to this problem in different ways, is affected by it in different ways, and therefore must respond to it in different ways.

In fact, one of the most positive benefits of the Special Envoy process has been the insight it has given us regarding both the similarities and the differences of the U.S. and Canadian experience with acid rain.

It is not the intent of the Special Envoy process to hide or gloss over the differences in the perceptions and policies of our two countires with respect to acid rain. Quite the contrary. We believe it is important that both the similarities and differences in these perspectives and policies be openly acknowledged and understood. It was not until we each had an understanding of the other country's point of view that we were in a position to formulate findings and recommendations. For this reason we have chosen to include in this report the following summaries of the U.S. and Canadian perspectives on acid rain.

A. U.S. Perspective on Acid Rain

Acid rain is a popular term used to describe a very complex chemical and atmospheric phenomenon that is more properly called acid deposition. It occurs when emissions of sulfur and nitrogen compounds are transported through the atmosphere, transformed by atmospheric chemical processes, and then deposited back again on earth in either a wet or a dry form. The interactions among these four factors — emissions, transport, transformation, and deposition — determine how much acidity is deposited in any particular area. The form and amount of this deposition, interacting with the unique sensitivities of specific receptor areas, together determine the nature and extent of environmental damage. In other words, the extent and magnitude of any damage caused by acid deposition are a function of all the steps of a very complex environmental process.

1. Emissions

Some of the sulfur and nitrogen compounds that are the precursors of acid rain are emitted by natural sources. Sulfur and nitrogen are natural components of the sea, soils, and organic matter; consequently, both sulfur and nitrogen compounds are regularly released to the atmosphere through organic and inorganic processes.

However, in the United States natural emissions of sulfur and nitrogen compounds are relatively insignificant contributors to acid rain. It has been estimated that in the eastern United States natural emissions of sulfur compounds are approximately three percent as large as man-made emissions. In the west they are probably somewhat larger, but still much less than 25 percent of man-made sulfur emissions. Even a major natural disaster such as the volcanic eruptions at Mount St. Helens emits relatively little sulfur compared to human activities. The total sulfur emitted by Mount St. Helens between March 1980 and March 1981, the period of greatest volcanic activity, was approximately the same as the annual sulfur emissions from two large coal-fired powerplants.

Clearly, man-made emissions of sulfur and nitrogen compounds contribute far more to acid rain in the United States than natural sources. They are emitted in much larger quantities and from a variety of widely distributed sources. Sulfur compounds are emitted into the air whenever the sulfur naturally present in fossil fuels and some ores is burned. The major sources of U.S. sulfur emissions are coal-fired electric powerplants, industrial boilers and processes, and ore smelting. Nitrogen oxides, on the other hand, are formed and released into the air when any kind of fuel is burned, because nitrogen and oxygen present in the air combine at high combustion temperatures. The major sources of U.S NOx emissions are transportation vehicles and industrial fuel combustion.

In 1983, U.S. SO_2 emissions were dominated by electric utility boilers, which emitted 14 million tons, more than 67 percent of the total 20.8 million tons emitted nationwide. Industrial boilers and processes emitted another 5.2 million tons (25 percent of total national emissions), of which 1.1 million tons were emitted by non-ferrous smelters. All other sources contributed the remaining eight percent of total national SO_2 emissions.

The amount of SO_2 emitted in 1983 represents a 28 percent decline from the peak level — 28.7 million tons — emitted in 1973. Electric utility SO_2 emissions declined by 19 percent between 1973 and 1983, and industrial emissions declined by 46 percent.

U.S. SO_2 emissions are concentrated along the Ohio River Valley in Illinois, Indiana, Ohio, Kentucky, West Virginia, and Pennsylvania. Those six states are among only ten in the country that emit more than one million tons of SO_2 annually. In 1980, 51 powerplants in those states emitted 25 percent of total U.S. SO_2. Two other high-emitting states, Missouri and Tennessee, are adjacent to the other six, and together those eight states emit 46 percent of all U.S. SO_2.

Recent trend data indicate that the nationwide pattern of SO_2 emissions has shifted. Between 1970 and 1980, virtually all increases in SO_2 emissions occurred in southeastern states. All but one of the states south of Missouri and Tennessee experienced increases in annual SO_2 emissions, while SO_2 emissions from all states northeast of Ohio and West Virginia decreased. Despite this gradual shift in emissions density toward the southeast, U.S. SO_2 emissions are still concentrated in the Ohio River Valley.

Total U.S. NOx emissions peaked during the 1970s and then declined slightly. In 1979, U.S NOx emissions totalled 21.1 million tons; by 1983 they had fallen to 19.4 million tons. Between 1970 and 1983 transportation NOx rose by 16 percent, and utility NOx rose by 40 percent. Overall, U.S. NOx emissions increased by only seven percent, from 18.1 to 19.4 million tons, between 1970 and 1983.

Although NOx emissions tend to be more evenly distributed over the United States than SO_2 emissions, the states along the Ohio River are especially high emitters of NOx as well as SO_2. Three of the five highest NOx-emitting states — Illinois, Ohio, and Pennsylvania — are also among the highest SO_2-emitting states. Thus national emissions of both SO_2 and NOx are concentrated in the Ohio River Valley and the immediately adjacent states. Ten states in the central and upper midwestern section of the United States — i.e., Missouri, Illinois, Indiana, Tennessee, Kentucky, Michigan, Ohio, Pennsylvania, New York, and West Virginia — emit 53 percent of total U.S. SO_2 and 30 percent of total U.S. NOx.

2. Transport and Transformation

Our understanding of the transportation of these pollutants in the atmosphere is a function of our general understanding of meteorological processes, supplemented by mathematical modelling. Under many meteorological conditions pollutants can be carried for hundreds of kilometers before they are deposited. Because of the high variability of both horizontal and vertical transport under different meteorological conditions, any given source can contribute to acid deposition over a very wide area.

As these pollutants move through the atmosphere, they can undergo significant chemical change. There can be dozens of different chemical reactions, some occurring simultaneously and others sequentially, which convert SO_2 and NOx to their acidic forms. The variability of the reactants involved in this chemical process, the presence or absence of clouds and water, and the availability of sunlight all contribute to the variability of atmospheric transformation.

3. Deposition

The process by which sulfates and nitrates are deposited out of the atmosphere back to earth is most commonly called "acid rain." Although rainfall is, in fact, one major way by which acidic compounds are removed from the atmosphere, they are also deposited by snow, sleet and fog. All these forms of deposition are collectively called acid precipitation. In addition to these various kinds of wet deposition, sulfur and nitrogen compounds can also be deposited in a dry form as either particulates or gases. The relative contribution of wet and dry deposition to acid rain is uncertain, but it is thought to vary significantly from location to location. Both wet deposition and dry deposition are believed to contribute to environmental damage, but their relative significance may vary from one kind of environmental effect to another.

Reliably quantifying the amount of acid deposited is a difficult task, especially if levels of acid deposition are to be compared at different times or at different places. Several different chemical species — e.g., sulphate ions, nitrate ions, and hydrogen ions — can be measured as an indicator of deposition, but they are not directly comparable. Because acid compounds are deposited in both wet and dry forms, an accurate quantification of acid deposition at any location would have to include both forms. Yet dry deposition is much more difficult to measure than wet deposition. Whereas a fairly good wet deposition monitoring system is in place (170 locations in the National Atmospheric Deposition Program (NADP) system), dry deposition data are much less precise, and there is yet to be deployed a national dry deposition monitoring network.

Furthermore, the levels of deposition measured at any given site are not easily comparable to levels of deposition at another site. Deposition patterns at a single site often show marked variations over time, depending on rainfall patterns and meteorological conditions. Acid deposition rates can vary widely within the same region; monitors only a few miles apart can measure markedly different rates of acid deposition over the same time period. These different problems, together with the fact that there was little interest in measuring deposited acidity until the 1970s, has limited current understanding of the patterns of acid deposition, especially insofar as those patterns can be compared from time to time and from place to place.

Despite all these limitations and uncertainties, it is possible to draw some general conclusions about acid deposition patterns in the United States. On the basis of data collected by several different monitoring networks, it is possible to compare the total wet deposition in 1980 of sulfate, nitrate, and hydrogen ions across the United States. The deposition patterns for all three are strikingly similar; the rates of highest deposition are found along a line stretching from the upper Ohio River Valley to northern New York. Areas of high acid deposition extend northeast and southwest from this core area, which encompasses parts of Indiana, Ohio, Pennsylvania, West Virginia, and New York. This area of highest acid deposition also coincides with the U.S. area receiving rainfall with the lowest pH.

For the United States as a whole, the total amount of sulfate wet-deposited in the eastern half of the country over one year is approximately five times greater than the amount of sulfate wet-deposited in the western United States. Approximately three times as much nitrate is wet-deposited in the east as in the west. The pH of rainfall is also lower in the east than in the west.

Beyond these generalities, however, it is very clear that there is a solid link between acidic emissions and acid deposition in the United States. The areas of highest acid deposition coincide with or are downwind and to the northeast of the areas of highest emissions.

4. Effects

The adverse effects of acid rain have been most clearly demonstrated in aquatic ecosystems. After acidifying compounds have been deposited in a watershed, they can be transported by surface runoff or through ground water aquifers to lakes or streams in the area. If the soils in these watersheds have only a limited natural ability to assimilate acidity, then prolonged acid deposition can result in surface water acidification. Such acidification can damage aquatic ecosystems, and in some circumstances it can result in the complete loss of game fish and other aquatic species.

For the past several years U.S. scientific attention has been focused on a number of acidified clear-water lakes in New York and New England. These lakes are found in areas with both high levels of acid deposition and little natural capacity to neutralize acidity. Until recently, there was no scientifically sound basis for determining whether these lakes were an isolated and unique phenomenon, or whether they were indicative of more widespread surface water acidity in the United States.

The U.S. government, through the Environmental Protection Agency and the National Acid Precipitation Assessment Program, has initiated a national surface water survey to project the population and distribution of lakes and streams at different levels of pH and acid neutralizing capacity. The final results of Phase I of the eastern lake survey are expected early in 1986. However, some preliminary results are now available.

The survey results are based on 1,620 statistically selected lakes found in potentially sensitive areas in the eastern United States. For sensitive areas in the New England area, the survey analysis estimates that 260 lakes (four percent of the total) have a pH lower than 5.0, with a 95 percent confidence that this number does not exceed 343. Approximately 1,360 lakes (19 percent of the total) are estimated to have acid neutralizing capacities below 50 micro-equivalents per litre (μel). The 95 percent upper bound confidence level is 1,533 lakes. The population of lakes with a μel level below 200 is estimated to be 60 percent of the total number of lakes. These data indicate that although the current number of acidic lakes is relatively small, the number of potentially sensitive lakes is relatively large. On the basis of this survey data alone it cannot be predicted what future acidification, if any, would occur if current levels of deposition were to continue. However, major research efforts are underway to address this issue.

Other areas covered by the survey include the upper midwest and the Florida peninsula. Survey data from the upper midwest reveal no acidic lakes. However, data from the Florida study area show a substantial number of lakes with a pH below 5.5 (20 percent of lakes surveyed) and below 5.0 (12 percent of lakes surveyed). The significance of the Florida data is still under review.

The extent to which acid deposition contributes to forest damage is much less well understood. In fact, it is not certain in what circumstances acid deposition may have significant detrimental effects on forest resources. However, forest damage is an area of major concern, and intensive research is being carried out by both U.S and Canadian scientists. This concern is reinforced by unexplained but unprecedented decline observed in some European forests. Scientists have developed several hypotheses to explain the observed symptoms, and many of these hypotheses involve acid deposition and related air pollutants.

Some changes in U.S. forests have been documented. For example, red spruce growing at higher altitudes in the Appalachian Mountains of New England and the Carolinas have been observed to lose their needles, and some have died prematurely. Some southern pine forests growing at lower elevations in the southeast appear to have experienced growth decline over the last decade. It may be the result of a single factor, or a combination of factors. Air pollution — including acid rain — may be involved either directly or indirectly. Field surveys and mechanisms research are now being inititated that will help to understand this problem better, but at this time the relationship between acid rain and forest damage in the United States is only conjectural.

The potential for acid deposition to degrade building materials is well recognized. Carbonate stone like marble and limestone, carbonate-based paints, and metals like galvanized steel all can be eroded and weakened in the presence of dilute acids like those found in acid deposition. The damage thus caused not only can result in economic loss, but the loss of cultural and historic resources as well. However, the extent of such damage in the United States is not known. Until materials inventories, acid deposition patterns, and the damage functions of specific materials are better understood, it will not be possible to accurately quantify the effects of acid rain on building materials in the United States. Without this quantification, it is difficult to determine the significance of acid deposition damage to building materials.

Finally, acid rain is not known to cause direct human health effects. However, indirect effects resulting from human ingestion of heavy metals dissolved by acids are of some concern. The theoretical mechanisms by which acid deposition could expose people to heavy metals are generally understood; however, to date the available data do not indicate any general occurrence of elevated exposures.

Acidic water can dissolve lead out of lead pipe and soldered joints, thus increasing the amount of lead in drinking water. A survey of New England water systems serving more than 25 people each does not indicate that heavy metal concentrations in the drinking water exceed health standards. Less is known about private water supply systems, and further investigation is warranted.

It is also thought that acidified lake and stream water can contribute to higher levels of dissolved mercury in the water, which in turn can increase mercury concentrations in fish. Although elevated mercury levels have been observed in some fish caught in certain New York lakes, it is not known whether mercury was naturally present in those waters or was primarily the result of acid deposition. In any event, no incidents of human health problems associated with heavy metals dissolved by acid deposition have been reported in the United States.

5. Current U.S. Response

The United States passed major legislation to protect air quality 15 years ago. The *Clean Air Act* of 1970 and the major amendments passed in 1977 have resulted in an air pollution control effort that has served as a model for many other industrialized nations, and has led to significant, measurable improvements in air quality in many parts of the United States.

Probably the single most important feature of the *Clean Air Act* is the establishment of National Ambient Air Quality Standards (NAAQS) for the most common air pollutants. The NAAQS require that ambient concentrations of those pollutants be limited to a level that protects public health and welfare. These national standards for both SO_2 and NOx have been in effect for more than ten years.

The individual states are responsible for ensuring that the NAAQS are met within their borders. In order to attain the federal standards locally, the states set emission limits on existing facilities. At this time, about 98 percent of the counties in the United States are in compliance with the national standards for SO_2 and NOx.

Another part of the *Clean Air Act* sets emission limits for different classes of new stationary sources. The Congress included this provision in the belief that emissions from new sources could be controlled at much lower cost than emissions from existing sources, and that the requirement to control new sources would encourage the development of more efficient and cost-effective control technologies. Furthermore, the control of new sources could lead to cleaner air as old facilities are replaced by new ones. To date, the United States has set New Source Performance Standards to control the emissions of SO_2 and NOx from coal-fired power plants, large industrial boilers, smelters, nitric acid plants, sulfuric acid plants, stationary gas turbines and petroleum refineries.

Besides controlling several kinds of stationary sources, the *Clean Air Act* also limits air emissions from new mobile sources. Standards to limit the emissions of NOx from new cars and light-duty trucks were first implemented in 1973, and they have been tightened since then.

These federal and state actions undoubtedly have helped preserve and protect air quality in the United States, an especially remarkable accomplishment considering the strength of the U.S. economy and the extent of U.S. industrialization. Total national emissions of SO_2 and NOx are well below what they would have been without controls. Total U.S. SO_2 emissions increased by about 56 percent between 1940 and 1970. After reaching their peak in 1973, total U.S. SO_2 emissions declined by about 28 percent between 1973 and 1983, despite the fact that electric utility coal consumption increased by about 60 percent during the same period. Flue-gas-scrubbing systems are now operating on over 47,000 megawatts of coal-fired electricity-generating capacity.

Between 1940 and 1970, total U.S. NOx emissions increased by more than 200 percent. Since 1970, however, total U.S. NOx emissions have remained fairly constant. Emissions from U.S. cars and trucks actually declined by nine percent between 1978 and 1983, despite a five percent increase in the number of vehicle-miles driven.

Yet during the same decade that the United States was making these advances in the control of SO_2 and NOx emissions, scientists, government officials, the Congress, and the American public became increasingly aware of acid rain, an environmental problem clearly linked to emissions of SO_2 and NOx. At the same time, the international aspect of acid rain was causing more and more concern. The attainment of national standards for SO_2 and NOx and the installation of SO_2 and NOx controls on new emission sources were not enough to prevent transboundary air pollution from contributing to environmental degradation in Canada.

There are several reasons why the *Clean Air Act*, as presently written, is not an especially good tool for controlling transboundary air pollution. For example, the NAAQS control ambient concentrations, not total loadings, but transboundary pollution is a total loadings problem. In fact, some of the techniques used in the past to attain ambient standards actually may increase total loadings. Tall smokestacks sometimes have been constructed to disperse emitted pollutants over wider areas and thus attain ambient standards locally. These tall smokestacks cause two problems: they allow more total pollutants to be emitted under applicable law; and they allow those pollutants to be transported further.

The New Source Performance Standards have been only marginally effective in reducing the total amount of acidic air emissions, because older facilities are not being replaced by new ones as quickly as once assumed. For example, most coal-fired powerplants once were believed to have useful lives of 35 to 40 years. It now appears that many old coal-fired powerplants may continue to operate for up to 60 or more years.

The fact that the *Clean Air Act* may not provide adequate protection for acid-sensitive ecosystems in both the United States and Canada has led several members of the U.S. Congress to propose new acid rain legislation. Several proposed bills have been debated in the Senate and the House of Representatives. None of them has been enacted into law, because none of them has been able to overcome the formidable barriers presented by conflicting economic and political interests.

In the United States the acid rain issue has been as politically divisive as any environmental issue the country has faced. The proposed solutions have pitted one region of the country against another; they have threatened the livelihood of coal miners in the east; they have raised the possibility of further increases in electricity rates in the industrial portions of the United States hardest hit by the recent recession.

The acid rain issue has been especially difficult to resolve precisely because proposed solutions must choose from a limited menu of control options. At this time, only three emission control techniques are proven and available for reducing SO_2 emissions from coal-fired powerplants: coal-washing, coal-switching, and flue-gas-scrubbing. However, one of these techniques could not be used to achieve substantial SO_2 reductions, and the other two impose different kinds of socio-economic costs, all of which are very high.

Coal-washing is a physical cleaning process by which inorganic sulfur is removed from high-sulfur coal, usually at or near the mine. This process is already being applied to some U.S. coal, because the costs of cleaning can be offset by lower transportation costs, higher combustion efficiencies, and lower boiler maintenance costs. However, coal-washing removes less than half the sulfur in high-sulfur coal; it is not used at all to clean low-sulfur coal. So its usefulness as an acid rain control technique is very limited.

Pound for pound of SO_2 removed, switching from high-sulfur to low-sulfur coal is usually the cheapest control option for coal-fired boilers. However, low-sulfur coal is much more plentiful in the western half of the United States; thus even though some low-sulfur coal is mined in the east, coal-switching would cause markets for western coal to increase, and markets for eastern high-sulfur coal to decrease. Eastern coal miners could be thrown out of work, and the communities in which they live — communities that were especially hard-hit during the recent recession — would suffer even more.

Flue-gas-scrubbing is a process by which sulfur is scrubbed out of the exhaust gases emitted by coal-fired boilers. Although the process is very expensive, especially when retrofitted on existing smokestacks, it allows the relatively clean combustion of high-sulfur coal. Thus the use of scrubbers to control SO_2 would not cost high-sulfur coal miners their jobs. However, it would raise the electricity rates of the businesses and families served by the utilities that install scrubbers.

Clearly, none of these control options provides a simple solution to the acid rain problem. Coal-washing cannot eliminate enough SO_2 to achieve a major reduction; coal-switching would cost high-sulfur coal miners their jobs; flue-gas-scrubbing would raise utility rates sharply. The availability of cheaper, more efficient control technologies would improve our ability to formulate a national response that is politically and economically acceptable.

The long-term value of control technology research has already been recognized by the U.S. government. Both the U.S. Department of Energy and the Environmental Protection Agency are managing research programs that are investigating a wide range of different control technologies. Taken together, this research offers the best hope for a long-term solution to the acid rain problem.

In the summer and fall of 1983, the U.S. government carried out a thorough review of the current status of acid rain knowledge and the options available for its management. From that review, the United States concluded that, although it was clear that acid rain was a serious concern both in the United States and Canada, it lacked the information needed to make a prudent decision on the need for or design of additional emission controls.

This policy was not a decision either for or against additional controls, but instead a choice to defer such a decision until a more adequate scientific and technical base was established. It is not U.S policy to wait for definitive answers on all major acid rain uncertainties before making a decision to act. Decisions on acid rain, like other environmental decisions, will always have to be made in the face of some scientific uncertainty. The United States is committed to act to control acid rain once it is reasonably certain that that action will achieve its intended results, and those results will justify the social and economic costs entailed.

B. Canadian Perspective on Acid Rain

1. Scientific Consensus

The Canadian public and governmental response to acid rain has been driven by the evidence of cumulative damage, the huge long-term socio-economic costs of allowing the damage to continue, and the view of the problem as presented by the community of international scientists. While recognizing that there are gaps in scientific knowledge, and that research should continue, Canadians generally have found very persuasive both the scientific findings and the urgent calls for action by many of these scientists.

In the past several years, thousands of scientific studies have been carried out and reports written on all aspects of the issue of acid rain. In addition, a number of syntheses and analyses of that work have been conducted. A careful review of the scientific literature indicates that there is a broad consensus within the knowledgeable scientific community on certain components of the acid deposition phenomenon. There follows a brief synthesis of the main areas of consensus. This is not intended to provide a complete picture of acid rain, much less the broader issue of pollutants transported long distances. Instead it seeks to lay out a basis of existing scientific consensus on which policy decisions may confidently be based.

Acid rain is not a natural phenomenon. About 90 percent of atmospheric SO_2 and NOx comes from man-made sources. Sulphur compounds are responsible for about two-thirds of the acidity in precipitation but produce most of the long-term acidity in sensitive water bodies.

While not part of the man-made problem, it should be noted that there are some locations where buildup of organic acids causes acidity of water and soil. Such acidification is different chemically from the man-made variety, and usually builds up very slowly. As a result, biological changes are also very gradual and are an integral part of the natural aging of such regions.

Man-made emissions of sulfur and nitrogen oxides move with major weather systems and are often transported many hundreds of kilometers. Transit time in the atmosphere increases the likelihood of chemical transformation from oxides to acid-producing sulfates and nitrates. Acid deposition is the result of these acidifying compounds coming out of the air through rain, snow, or dry deposition.

Large areas of North America — in particular, eastern North America — are underlain by rocks and soils that make these areas vulnerable to acidification. In these areas, deposition of acidic pollutants over time acidifies streams, lakes, and soils.

As acid rain changes the chemistry of those ecosystems, it also alters their biology. Specifically, many important species that depend on the water become extinct as it turns acid. Some are of economic and cultural importance.

Over many years, deposition of man-made acids has increased the acid content of surface waters in vulerable parts of industrialized countries. In some of those areas, highly acidified lakes can no longer support some species of fish and other life forms. There is a clear and direct relationship between increasing acidification and the deleterious changes in biological populations.

Acid rain also is acidifying some soils in these vulnerable regions. In the process, it may leach away nutrients and bring about changes to biological organisms that help maintain the productivity of the soil. In exceptional circumstances, acid rain can leach nutrients directly from tree foliage.

Recently, widespread damage to forests has been observed in eastern North America and in Europe (where it is much more advanced). This decline phenomenon is spreading rapidly. It is incompletely explained, but the damage is spatially linked with major pollution emission regions. The contribution of acidic pollutants to this problem has not been satisfactorily determined but is generally perceived in the scientific community to be a contributing factor, together with other pollutants, notably ozone. There is mounting evidence that this tree "dieback," as well as serious growth retardation, are beginning to increase dramatically in some species.

Toxic heavy metals emitted and deposited more or less in conjunction with acidic pollutants, or mobilized from soils and rocks by the heightened acidity of circulating water, have a variety of toxic effects on plants and animal life. There is evidence of increased concentrations of certain heavy metals in acidifying water.

The pollutants that cause acid rain, while suspended in the atmosphere, reduce the amount of sunlight and so contribute to slower growth of crops and forests. They also reduce visibility, a fact of special importance in tourist regions.

Corrosion of materials is accelerated by fallout from the atmosphere of sulfur dioxide gas and other pollutants.

Because of day-to-day variability in weather patterns, atmospheric modelling and direct observation do not usually enable precise linkages to be made between individual emission sources and individual deposition-receptors. But on a broader scale, and over time, fairly accurate links can be made. Also, on a continental, multi-year scale, the relationship between total emissions and total deposition is almost linear. Thus a major, generalized reduction in emissions of sulfur and nitrogen oxides in eastern North America over several years would bring about a commensurate reduction in deposition of acidifying compounds.

At current rates of emission of acid-forming pollutants, acidification of sensitive environments will continue even if there is no increase in total emissions. Consequently, acid rain and its environmental, biological, and economic consequences will similarly continue. Indeed, damaging acidification of many ecosystems would continue even with some decreases in total emissions, although any significant reduction would slow the rate of acidification.

Observation of acid-sensitive surface waters offers guidance on acceptable levels of acid rain. By and large, moderately sensitive systems in eastern North America tend not to exhibit increased acidity if the total annual deposition of wet sulfate is below 20 kilograms per hectare. Thus, although the dry fraction of acid deposition is not yet being measured effectively, empirical data show that, in linking total acid loadings to acidification of sensitive waters, the wet sulfate fraction generally is an acceptable yardstick.

There is consensus in the international scientific community that the scientific data base is adequate to assess the immediate as well as the long-term implications of continuing, high-volume emissions of acid-causing pollutants and resulting acidification of sensitive ecosystems. The scientific data base is similarly adequate for the selection of effective emission reduction strategies to reduce substantially the effects of acid deposition.

2. Sources

The Special Envoys have been directed to examine the problem of acid rain in its international, transboundary context. A Canadian analysis of the sources of acid rain similarly must encompass the transboundary and the domestic components. After all, of the acid rain affecting eastern Canada, about one-half originates in the United States and one-half in Canada. In the regions of particular concern in Canada, such as the Muskoka-Haliburton tourist and recreation area in Ontario, two-thirds of the acid rain originates in the United States. Overall, the United States exports about four times as much SO_2 as it imports from Canada each year.

Air pollution became a major public concern in Canada, as it did in many industrialized countries, in the period of high industrial growth following the second world war. By the 1970s, many countries, Canada included, had passed clean air laws, which addressed in the main the most serious air pollution problem of the day: poor air quality, chiefly in urban centres, and its impact on human health. One of the ways of doing so, and often the cheapest, was the erection of tall smokestacks, to enable air currents to disperse pollutants more widely.

As a result, any progress in reducing acid precursor emissions has come almost entirely from attempts to meet local air quality standards. These attempts have met with a measure of success: in central and eastern Canada, for example, total SO_2 emissions dropped from 5,640 kilotonnes in 1970 to 4,516 kilotonnes in 1980. Fewer than one percent of Canadian regions currently fail to meet air quality objectives (including, in most acid-sensitive regions, a strict one-hour SO_2 standard).

But this downward trend may not continue. If additional steps are not taken, Canada estimates that the total of SO_2 emissions potentially affecting its acid-sensitive regions will rise by about 10 percent by the year 2000.

There are three main reasons for this:

1. Since local air quality is generally quite good in most localities, the principal legal imperative to bring down emissions has largely been satisfied;
2. Economic growth and other factors are resulting in expansion of some of the major sources of acid gas emissions; and
3. Some old and heavily polluting facilities, chiefly high-sulfur coal-burning power plants, are not being replaced as quickly as anticipated by new, cleaner facilities.

Another way of looking at the total loading of acidic pollutants in Canada is by industrial sector. Thus, about one-half of the acid rain falling on Canada results from emissions from coal-burning power plants, another quarter from smelters, and the remainder from other industrial sources and transportation.

Although in recent years there has been a reduction in total SO_2 emissions affecting Canada, what is significant is that they remain near their historical peak. The emissions of the other main acid-causing gas, NOx, are continuing to rise significantly. Total emissions will need to be cut sharply if the adverse effects of acid deposition are to be reversed.

Another factor in the increasing acidity of rainfall is a change in the way in which coal is burned. Although total usage of the coal that contributes to the Canadian acid rain problem has not increased significantly, seasonal use has changed dramatically. Summertime coal consumption is now much greater than it was several decades ago, due to increased use of air conditioning. Summertime heat and humidity hasten the transformation of SO_2 and NOx emissions into acid rain. And the construction of tall stacks means that the pollutants travel greater distances, damaging previously pristine regions.

Thus, even though overall coal consumption has not changed greatly, the sulfates and nitrates that cause acidity have increased significantly.

In summary, between 1940 and 1970, man-made emissions of SO_2 impacting on Canada rose by about two-thirds. Implementation of clean air laws produced a generalized reduction over the past 15 years. It is the Canadian perception that, unless additional measures such as the new Canadian reduction program are implemented, the total emissions of SO_2 affecting Canada will increase into the next century. NOx emissions will increase at an even higher rate.

3. Impacts

The various economic and ecological consequences of acid rain are discussed elsewhere in this report. What makes transported air pollutants, and especially acid rain, such a vexing issue in Canada is the fear of long-term, essentially irreversible, harm to sensitive environments, and consequent disruption of communities and lifestyles.

The long-term socio-economic impacts of acid rain in Canada should be viewed in the following terms:

- More than four-fifths of Canadians live in areas of high acid deposition. Many of them live, work, or spend leisure time in acid-sensitive regions.
- The fishery, tourism, and forestry resources potentially at risk due to acid rain sustain about eight percent of Canada's gross national product.
- Of the two million lakes in Quebec and Ontario, 43 pecent are vulnerable to acidification.
- About 90,000 jobs are at risk in the eastern Canadian commercial fisheries.
- Of the 16,000 fishing camps and lodges in Ontario, 600 may be closed because of acid rain by the year 2000.
- More than 70 million hectares (or about one-half) of Canada's productive forests are in areas receiving high levels of acid rain. These forests generated 14 billion dollars' worth of forest products in 1982.

Such gross statistics do not begin to reflect adequately the current frustration and potential long-term harm in affected communities.

In general, acid-sensitive regions are relatively sparsely populated, not highly industrialized, and heavily dependent for their economy and lifestyles on a healthy and productive environment. Canadians living there perceive that their future is being put at risk because areas of high industrial activity are keeping their production costs down by exporting pollution. This perception of inequity and increasing long-term harm, especially when some of the pollution crosses the international border, is at the root of the Canadian view that emissions of acid gases impacting on Canadian territory must be reduced to levels that the environment can accommodate.

4. Co-operative Actions

Acid rain has become a politically sensitive issue in both the United States and Canada. Because of the large costs of substantially reducing the emission of pollutants that produce acid rain, the much less easily quantified, but also very large, economic, social, and aesthetic costs of inaction, and both the perception and the reality of incomplete scientific understanding, effective policy responses have not been easy to come by.

In Canada, for a number of reasons, it has been easier to move toward major reductions of the pollutants primarily responsible for excess acidity in precipitation. Canada has now embarked on such a program.

In the United States, many factors have combined to make a national response more difficult to achieve. Canada recognizes these difficulties, particularly when proposals involve legislative initiatives. At the same time, Canada believes the U.S. *Clean Air Act* affords opportunities, through implemented or as yet unused regulatory mechanisms, to take significant steps toward reducing emissions of acid gases.

5. Current Canadian Response

Air pollution control in Canada is a shared, concurrent responsibility of the federal and provincial governments. The provinces are primarily responsible for controlling emissions which impact within their borders, while the federal government is responsible for international air pollution. Both levels of government play a role in interprovincial air pollution.

Except for pollutants dangerous to human health, Canadian air pollution control programs are generally designed to achieve specified environmental quality objectives rather than prescribing the use of specific technologies. Air quality objectives for SO_2 have been published by the federal government for the guidance of the provinces. The Canadian acceptable levels result in air quality that is at least as healthy as that in most industrialized countries, while the Canadian desirable levels are among the most stringent anywhere. In addition, the one-hour (rather than 24-hour) standard helps deal with total loadings by reducing opportunities for excessively high emissions.

The following table summarizes Canadian SO_2 air quality objectives:

SELECTED CANADIAN SO_2 AMBIENT AIR QUALITY REQUIREMENTS

(micrograms per cubic metre)

Averaging Period	Canadian Objectives		Ontario
	Desirable	Acceptable	Requirements
Annual	30	60	55
24-hour	150	300	275
1-hour	450	900	690

Most provinces base their control programs on the acceptable level; two use the desirable level.

Thus sulfur dioxide, as a local air quality problem, has been controlled successfully in Canada. This was achieved through a variety of actions including emission containment, use of tall smokestacks, use of low-sulfur fuels, intermittent control procedures, and fuel regulations.

Canadian non-ferrous smelters have used selective mining and mineral separation preparation practices, sulfur containment, and changes in process technology to reduce emissions. Regulations limiting the sulfur content of fuels have reduced non-utility fuel use emissions. Canadian utilities have used natural gas, low-sulfur coal, coal-blending, coal-washing, nuclear and hydraulic generation, and load management to limit increases in emissions.

The above summarizes the Canadian response to the problems of local air quality. While this is not a response to the problem of acid rain (and indeed exacerbated that problem by use of dispersion techniques), it serves as a foundation on which current acid rain mitigation programs are being erected.

The reductions of air pollutants that have occurred in Canada since 1970 have not alleviated the long-range transport and long-term loading problems of which acid rain is a part. Canada has therefore determined that substantial further emission reductions must take place to stem the damage being caused by acid rain. Accordingly, a Canadian acid rain abatement program is being put in place.

The scale of the Canadian program is based on the scientific evidence that most moderately sensitive regions can be adequately protected if annual loading of wet sulfate is kept below 20 kilograms per hectare. Reducing loadings to that level for most eastern Canadian acid-sensitive regions requires a reduction in impacting SO_2 emissions of close to 50 percent from 1980 levels. The scale of reductions agreed for central and eastern Canada has been set on that basis, and as the Canadian component of an adequate abatement program.

In March 1985, the Environment Ministers of the governments of Canada, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland agreed to reduce SO_2 emissions from the 1980 base by approximately 50 percent by 1994. At the same time, they agreed to an initial interprovincial allocation of reductions.

A tabular summary of past and projected changes in total central and eastern Canadian SO_2 emissions by sector follows:

SULPHUR DIOXIDE EMISSIONS

(thousands of metric tonnes per year)

	1970	1980	1990	1994
Smelters	3,810	2,720	2,000	1,150
Utilities	470	730	450	450
Non-utility Fuel Use	950	580	400	300
Other	410	490	400	400
Total	5,640	4,520	3,250	2,300

The provinces are in the process of enacting regulations to implement the new program. The two largest provincial emitters of acid gases, Quebec and Ontario, have now done so. Together they account for three-fourths of eastern Canadian SO_2 emissions.

The main elements of the Quebec and Ontario programs are summarized in the following tables.

QUEBEC
SO_2 Emission Controls
Legal Limits and Effective Dates

(thousands of metric tonnes per year)

	1980	1990
Noranda	552	275
Murdochville	91	65
Other Industrial Sources	135	116
Fuel Combustion	258	102
Transportation	49	39
Total	1,085	597

ONTARIO
New Package of SO_2 Emission Controls
Legal Limits and Effective Dates

(thousands of metric tonnes per year)

	1980	1994
Ontario Hydro	452	175
Inco	1,155	265*
Falconbridge	154	100
Algoma (Wawa)	161	125
Other Sources	272	220
Total	2,194	885

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* In addition, an even tighter objective has been set at 175 kilotonnes/year by 1994. Inco's December 1988 report must describe in detail the technology and design which could be used to meet this lower objective and its cost.

In addition, the Ontario government is preparing a regulation to control new or modified boilers. It will place a one percent sulfur content constraint on the fuel or will require that an equivalent amount of SO_2 be removed from flue gas.

As part of this abatement program, the federal government is taking several steps in co-operation with provinces and the private sector:

- Limits have been set for new motor vehicle emissions to bring them to U.S. standards by September 1987.
- $25 million have been allocated to cost-share with industry the development and demonstration of new processes and pollution control techniques for non-ferrous smelters.
- $150 million have been allocated to cost-share, with provinces and industry, the implementation of these new techniques.
- A $30 million federal-provincial scientific research program is continuing, and is aimed in part at monitoring the efficacy of the Canadian abatement program.

These planned reductions are significant not only for their size, but also for the policy judgments on which they are based. They go beyond traditional concerns with improving local air quality, and address specifically the total pollution loading issue which is the cause of acid rain.

V. RECOMMENDATIONS

In preparing our recommendations to both governments, we have been conscious of the wide differences between our two countries on this issue, differences that are based not just on perception but also on certain underlying political, social, economic, and geographic realities. We have also kept in mind that our mandate was not to find a final solution to this bilateral problem, but to find ways in which our two countries can begin to move together to deal effectively with this vexing issue.

Both nations want to see progress on acid rain. For such progress to be possible, and if it is to result in part from the work of the Special Envoys, our recommendations must be realistic. They must not ask either country to make a sudden, revolutionary change in its position. They must not call for immediate abandonment of major policy stands. They must instead point the way to a resumption of fruitful bilateral dialogue and constructive action that will help us relieve the stress that this issue has created, and reduce the flow of airborne pollutants across our common border.

A. Innovative Control Technologies

A significant impediment to the development of a U.S. consensus on acid rain is the high cost of the available control options. Because the impacts of different options fall on different interest groups, political positions have become polarized, and it has become increasingly difficult to find a common ground for action. If the menu of control options were expanded, and if the new options were significantly cheaper yet highly efficient, it would be easier to formulate an acid rain control plan that would have broader public appeal.

Recommendation

Therefore, the U.S. government should implement a five-year, five-billion-dollar control technology commercial demonstration program. The federal government should provide half the funding — 2.5 billion dollars — for projects which industry recommends, and for which industry is prepared to contribute the other half of the funding.

Because this technology demonstration program is meant to be part of a long-term response to the transboundary acid rain problem, prospective projects should be evaluated according to several specific criteria. The federal government should co-fund projects that have the potential for the largest emission reductions, measured as a percentage of

SO_2 or NOx removed. Among projects with similar potential, government funding should go to those that reduce emissions at the cheapest cost per ton. More consideration should be given to projects that demonstrate retrofit technologies applicable to the largest number of existing sources, especially existing sources that, because of their size and location, contribute to transboundary air pollution. In short, although the primary purpose of this research program is to demonstrate the kinds of technologies that would be needed for any future acid rain control program, it should also result in some near-term reductions in U.S. air emissions that affect Canadian ecosystems.

Furthermore, special consideration should be given to technologies that can be applied to facilities currently dependent on the use of high-sulfur coal. Because the scrubbers currently available to clean high-sulfur coal are very expensive, there is an economic incentive for sources to switch to low-sulfur coal as a method of reducing emissions. However, coal-switching imposes significant socio-economic costs on high-sulfur coal miners, their families, and their communities. The commecial demonstration of innovative technologies that clean high-sulfur coal will help to reduce the economic consequences of any future acid rain control program.

We further recommend that a panel, headed by a senior U.S. cabinet official, be established to oversee this research demonstration program and select the projects to be co-funded by the federal government. The U.S. Environmental Protection Agency and Department of Energy should provide the technical expertise necessary to select demonstration projects. Other members of the panel should be drawn from the Department of State and state governments. Canada also should be invited to send a representative to sit on this panel.

In this connection, we note a somewhat similar approach being taken in Canada. There, the major industrial sources of acidic emissions are smelters. As part of the Canadian acid rain mitigation program, federal and provincial governments are co-operating financially with industry to develop and implement advanced technologies designed to improve smelter efficiency and reduce pollution.

Recommendation

The results of the Canadian technology development program should be shared with the United States.

B. Co-operative Activities

The Special Envoys have recognized the need to put in place mechanisms to help both governments deal with this issue in such a way that differences are not exaggerated and oppportunities for co-operation and agreement seized.

1. Domestic Legislation and Regulations

The U.S. and Canadian Clean Air Acts, and other legislation and regulations that delimit the emissions of airborne pollutants, were designed and are being implemented primarily to respond to air quality needs within each country. But both Acts recognize that special controls might be required to deal with pollutants that cross the interntional boundary.

Various scientific experiments, measurements, and observations demonstrate the reality of the transboundary flow of airborne pollutants. As a consequence, the interpretation by regulatory agencies of relevant domestic legislation can have an impact, albeit unintended, on the nature and quantity of pollutants that cross that border.

Recommendation

Both the United States and Canada should review their existing air pollution programs and legislation to identify opportunities, consistent with existing law, for addressing environmental concerns related to transboundary air pollution. The results of these reviews should be made available to the chief environmental officials of both countries for their consideration in the management of their respective programs.

In implementing air pollution legislation, agencies in both countries have tended to focus on local, domestic parameters. But clean air regulations obviously can have a transboundary effect. Therefore prior notice and consultation on such rulemaking is essential.

Recommendation

Agencies contemplating changes to laws or regulations that may alter the flow of transboundary pollutants should give timely notice of their intent to agencies of the other country through diplomatic channels.

2. Bilateral Consultation and Information Exchange

Acid rain, and other forms of long-range, transboundary air pollution, comprise a complex phenomenon with important political, economic, social, and environmental implications for both countries. Both domestically and as a bilateral issue, therefore, acid rain is not susceptible to a quick-fix response. It must be assumed that it will remain on the bilateral agenda for some time, and that its intrinsic importance will dictate that it be handled at the highest levels.

Additionally, the Parliament of Canada and the U.S. Congress have maintained a keen interest in this issue. While their principal focus has been on legislation in response to perceived domestic problems, both bodies have shown an awareness of the transboundary flow of airborne pollutants and its political and diplomatic ramifications. Both bodies have passed ammendments to the Clean Air Acts explicitly recognizing the potential for damage by pollutants crossing the international boundary and setting out means for reciprocal action designed to control pollutants deemed to cause such damage.

Recommendation

Acid rain should remain high on the agenda of meetings between the President and Prime Minister. They should be prepared to intercede personally from time to time to resolve difficulties and ensure progress. The U.S. cabinet official heading the technology development panel and a Canadian cabinet official would jointly advise the President and Prime Minister.

Heretofore preparations and briefings of Cabinet officers on acid rain have been separate and unilateral; henceforth, at least some of those briefings should be prepared on a co-operative basis. Moving in this way toward common perspectives for political-level discussions is a way to broaden the areas of accord.

Recommendation

Our two governments should establish a bilateral advisory and consultative group on transboundary air polution. Such a group, comprising both diplomatic and environmental management officials, should provide the forum for discussions and first-level consultations on issues related to transboundary pollution. It should also provide advice to the directors of each country's environmental programs and to the Secretary of State and Secretary of State for External Affairs.

C. Research

Scientific information provides a basis for determining the most effective actions to address the damage caused by acid rain and other long-range, transboundary air pollutants. There are several areas where research would be of special value to decision makers in guiding the development of environmental policies.

The following research recommendations are not listed in priority order. The decisions on which areas are of greatest concern are a matter of public policy to be determined by each nation. However, through the combined efforts of our two countries, active research efforts should be pursued in each of the areas listed.

1. Deposition Monitoring

Although methods for monitoring wet deposition are well established and extensive standardized networks are in place across North America, total deposition is not being measured adequately. Dry deposition has been measured at specific sites using a variety of techniques, but no comprehensive monitoring network for dry deposition is currently in place. Measurements of dry deposition would permit more accurate evaluation of the total impact of acid deposition.

Recommendation

Standard, accurate methods to measure dry deposition should be developed and monitoring networks deployed. The networks should be of sufficient size and adequate statistical design, and implemented with adequate quality assurance and quality control procedures, in order to enable researchers to measure total acid deposition for sensitive areas across North America.

2. Rates of Aquatic Change

Concern over the effects of acid deposition first began with the observation that atmospheric deposition is causing the acidification of surface waters and subsequent adverse effects on aquatic biota. Although much research has been conducted during the last decade, our understanding of what changes in water quality would result from a change in acid deposition in a variety of watershed types is still incomplete. The factors controlling watershed processes are also not well known. Information on dynamic watershed processes would improve our ability to predict changes in water quality from current and future deposition levels.

Recommendation

Process-level data from different watershed types would be of help for determining current and potential future effects of acid deposition on surface waters. Models for predicting watershed response to acid deposition should be developed and tested empirically. In addition, an adequate acid deposition data base on watershed characteristics should be developed to exercise the models for selected North American sensitive areas.

3. Aquatic Biology

Concern over the change in surface water chemistry due to acid rain stems from the subsequent potential for effects on aquatic biota, particularly fish. Effects of specific pH levels have been ivestigated, but the effects of chronic or slow acidification, and the relationships between trace metals and fish species, have not been adquately detemined. The loss of fish in acidified surface waters may be one of the last effects to be observed. Effects on biota other than fish should also be considered.

Recommendation

The environmental damage of surface water acidification should be understood in terms of biological changes. This would help to quantify the relationship between changes in surface water chemistry and changes in aquatic biota more clearly. Special attention should be focused on both rates and types of biological change.

4. Forest Effects

Forest and tree declines in North America and in Europe have been documented in areas that receive high levels of atmospheric deposition. The concern about the possible effects of acid rain on forests is prompted by some provocative, albeit largely circumstantial, evidence. Despite the existence of observed changes in forest growth in certain areas, it is unknown to what degree, if any, current levels of acid rain are affecting the growth and productivity of forests in North America.

Recommendation

Research should be accelerated to investigate the potential link between forest and tree decline and acid rain as a causal or contributing factor.

5. Materials Damage

Materials damage is one of the few effects of air pollution that has the potential to be quantified economically. Fewer resources have been expended on this area of research than on the biological effects of atmospheric transport; estimates of damage have varied widely, but some have gone as high as several billion dollars annually. Equally of concern is the possibility that irreplaceable cultural resources may be damaged or destroyed.

Recommendation

The effects of acid rain on materials should receive increased attention so that the quantification of the extent of current damage, the resources at risk, and the prognosis for future damage can be improved.

6. Role of Heavy Metals

Heavy metals such as lead, mercury, cadmium, and arsenic become more soluble in solution at lower pH. All of these metals can be toxic to both aquatic biota and humans. The increased corrosivity of acidic water on water storage and distribution systems may also pose a potential health risk. The extreme toxicity of these metals warrants concern.

Recommendation

The mobilization, transport and flux of heavy metals in acidified surface waters should be investigated to determine their environmental toxicity. Special emphasis should be placed on potential effects on human health and on possible mitigation strategies. The role of these metals in aquatic and forest damages also needs more attention.

The **Chairman**. Senator Ford, do you have a statement you would like to make at this time?

STATEMENT OF HON. WENDELL H. FORD, A U.S. SENATOR FROM THE STATE OF KENTUCKY

Senator **Ford**. Yes, Mr. Chairman, I do, and I will make it brief.

I sincerely congratulate you for holding oversight hearings today and tomorrow on clean coal technology and acid rain. The key to America's energy future and to the solution of part of the problem of acid deposition is our ability to burn cleanly our most abundant energy resource, coal.

The trouble with all the proposed acid rain control strategies to date is, they lock in the obsolete technology of the 1960's and give no acknowledgement to the promising technologies of tomorrow.

The House of Representatives, the Waxman bill, H.R. 4567, represents the same old tired, ineffective approach to the problem of acid rain. That bill represents all that is wrong with our efforts to limit acid rain.

This hearing on the Clean Coal Technology Program represents all that is right and hopeful in what our approach to acid rain should be, and, Mr. Chairman, I ask that the balance of my statement be included in the record as if given.

The **Chairman**. Your full statement will be included in the record.

Senator **Ford**. Mr. Chairman, I have a letter to Chairman Waxman—he did not particularly like it, but I thought it was awful good—[general laughter]—to be inserted in the record also.

The **Chairman**. It will be inserted in the record at this point.

[The prepared statement of Senator Ford and letter referred to follow:]

STATEMENT OF SENATOR WENDELL H. FORD
Hearing: Clean Coal Technology/Acid Rain Control
Committee on Energy and Natural Resources
June 9, 1986

Mr. Chairman:

I sincerely congratulate you for holding oversight hearings today and tomorrow on clean coal technology and acid rain. The key to America's energy future and to the solution of part of the problem of acid deposition is our ability to burn cleanly our most abundant energy resource -- coal.

The trouble with all proposed acid rain control strategies to date is that they lock in the obsolete technology of the sixties and give no acknowledgement to the promising technologies of tomorrow.

In the House of Representatives, the Waxman bill, H. R. 4567, represents the same old, tired ineffective approach to the problem of acid rain. That bill represents all that is wrong with our efforts to limit acid rain. This hearing on the clean coal technology program represents all that is right and hopeful in what our approach to acid rain should be.

The great expense of installing these cumbersome and outdated scrubbers provides little incentive for coal-burning facilities to continue to use what would become non-compliance coal, with the result that massive dislocations of both coal markets and mining communities will occur.

A little known fact, but an extremely important one, is that there are very limited low-sulfur reserves in Kentucky, the nation's leading coal producing state, and in the rest of the Eastern United States. For example, of the nation's low-sulfur coal which would meet a 1.2 pounds of SO2 per million BTU standard, 85 percent is found in the West and only a third of Kentucky's reserves qualify.

Passage of any of the legislative proposals before the Congress today would be an unmitigated disaster. If we simply mandate sulfur emissions reductions now, we will cause many to invest in old, inefficient scrubber technology. That is why these hearings today are so important. I look to this forum to determine the status of the most promising of the clean coal technologies, to tell us how soon we can expect those most far along to become economically feasible, and what quantum leaps we can expect in the future.

I have always been second to none in my support for a strong clean coal research and development program, and can tell you we have come too far to lose the progress that has been made. We have devoted too much time and money to the development of clean coal technologies not to incorporate them into acid rain control strategies. I hope these two hearings will serve to bring this point home and will enable those of use who are concerned about acid deposition and the clean burning of coal to develop a sound strategy to solve the two problems.

We need to think hard about some complementary approaches to commercializing clean coal that make use of the energies of the private sector. I am impressed that the PURPA program we started several years ago has functioned to focus a great deal of interest on new technology to burn gas. I'd very much like to see that same kind of energy turned to developing ways to burn coal cleanly. I will be listening to all the witnesses today and tomorrow to see if any new ideas of this sort turn up.

WENDELL H. FORD
KENTUCKY

United States Senate
WASHINGTON, DC 20510

COMMITTEES
COMMERCE, SCIENCE
AND TRANSPORTATION
ENERGY AND
NATURAL RESOURCES
RULES AND
ADMINISTRATION

June 6, 1986

Dear Mr. Chairman:

I appreciate the opportunity to submit a statement for the record and regret that your subcommittee schedule did not leave room for Congressman Rogers and I to testify.

The Commonwealth of Kentucky is the nation's leading coal producing state and a leader in the field of clean coal technology. While Kentucky recognizes that acid deposition is a significant environmental problem, we do not believe it is so devastating that an "acid rain control plan" must be passed today. Every legislative proposal pending in both Houses would lock in scrubbers, which are the outdated pollution control technology of the sixties, raise residential electricity bills, and cause serious dislocations in coal markets -- and all are based on incomplete scientific evidence that nowhere guarantees a set reduction in SO2 emissions would result in a commensurate reduction of acid deposition.

Serious scientists disagree on the urgency of "doing something now" about acid rain. Regarding aquatic effects - probably the most demonstrated adverse effect of acid deposition - the scientific consensus, including the last two reports by the National Research Council, appears to be that the number of lakes and streams at risk may be much lower than previously believed; that the rate of surface water acidification is much slower than once claimed; and that the effects of acidification, where it has occurred, may be reversible. While acid deposition is a potential contributor to forest decline, it is known that other pollutants - particularly ozone and other gaseous oxidants - do have adverse effects on forests and crops. As an example of language pollution, many people are mistakenly assuming that ozone and other oxidants are part of acid rain, and that they will be controlled by legislation aimed largely at reducing sulfur emissions. Efforts to preserve forest health by controlling "acid deposition" in this way could very well be misdirected.

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The costs of control must be considered, and the costs should be compared with expected benefits. People have been led to believe that passage of legislation will "stop acid rain" and any associated damage. It will not. It is largely agreed by scientists that even very ambitious - and costly - reductions in sulfur dioxide emissions will have a very small impact on the pH of rainfall. For example, researchers at the Massachusetts Institute of Technology estimated that total elimination of sulfur dioxide emissions from all power plants in the U.S. would increase the pH of rainfall in the northeastern U.S. from the current 4.2 to about 4.4.*

H.R. 4567 would have significant consequences for Kentucky in a number of ways. One is the effect on our coal markets. The Office of Technology Assessment has estimated that 90 percent of the Kentucky coal delivered to electric utilities in 1980 would not meet a 1.2 pounds of sulfur dioxide emission limitation.** The Kentucky Energy Cabinet has estimated that 72 million tons or 75 percent of the Kentucky coal delivered to electric utilities in 1983 did not meet a 1.2 pounds of sulfur dioxide emission limitation and was delivered to utilities without any existing flue-gas desulfurization equipment.*** This coal production - 72 million tons annually - would be a risk under H.R. 4567, as would the jobs of the approximately 24,000 coal-miners who mined it.

These figures are not intended as projections of net production or net employment impacts. Several factors prevent equating the non-compliance quantities with production impacts. However, they do serve as a good measure of the expected economic disruption. While

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*Fay, James A., Dan Golomb, James Gruhl,
Controlling Acid Rain,
Massachusetts Institute of Technology, April, 1983

**Office of Technology Assessment,
The Regional Implications of Transported Air Pollutants,
July, 1982.

***Kentucky Energy Cabinet,
Analysis of H.R. 4567,
May, 1986, Lexington, Kentucky.

production of selected low-sulfur coal seams could increase, this is of little consolation to miners who become unemployed, their families and their communities. It must be understood that mining operations are not like offices. One cannot simply move a chair and desk and begin work at a new location. A fact that very few understand is there are very limited low-sulfur reserves in Kentucky and in the Eastern U.S. For example, of the nation's low-sulfur coal which would meet a 1.2 standard, 85 percent is found in the Western U.S. (see Table 1). Only a third of Kentucky reserves would meet this standard (see Table 2).

Kentucky can do little to protect its potential market losses. The vast majority of the non-compliance coal delivered to utilities - 88 percent - was delivered to out-of-state utilities. These are utilities over which Kentucky has no control; the state cannot influence the adoption of FGD equipment to reduce emissions and therefore cannot prevent these utilities from switching to non-Kentucky coal. The coal delivered to utilities in Kentucky will also create problems. Special interests - high-sulfur coal producers versus very-low-sulfur coal producers, rate-payers versus employment concerns - will make policymaking within Kentucky difficult.

A second consequence of the legislation is the impact on electricity rates. While estimates vary, and the effect of the trust fund is uncertain, the Office of Technology Assessment estimated that Kentucky could face among the highest rate increases. For the citizens of the state that already has more FGD units than any other state, this is a bitter pill to swallow; this is difficult to explain to the citizens who have already seen - and paid for - a 50 percent reduction in SO2 emissions. I have never been able to understand why none of the legislative proposals of the past years and why H.R. 4567 ever give Kentucky credit for any of the clean up it has done prior to 1980 under the Clean Air Act.

The states that did something early about clean air are penalized by every proposal now before the Congress. Kentucky is a good example. In 1976 when the Clean Air Act was put fully in place, Kentucky sulfur dioxide emissions were 1.54 million tons. By 1980 emissions were reduced to

1.11 million tons - a 430,000 ton clean-up. Emissions have been further reduced in 1985 to 878,000 tons - a reduction from 1980 of some 232,000 tons.

Kentucky is credited with these 232,000 tons under legislation pending but not the earlier 430,000 tons made in 1976-80 since full implementation of the Clean Air Act.

Mr. Chairman, the states that were Johnny-come-lately to clean up benefit under all the bills. The states, like Kentucky, making an early effort are penalized.

The approach we recommend - and one in which Kentucky has invested over $100 million since it began under my tenure as Governor in 1974 - is to develop, demonstrate and commercialize new technologies which will utilize coal more efficiently and with less emissions. I believe it is more sensible to spend our money for new, improved technologies than to spend those same resources retrofitting outdated facilities with inefficient controls. The expected increase in efficiency will be an inducement for utilities to replace existing plants. The normal progression of replacing old plants with newer, more efficient and less polluting plants has slowed in recent years for a number of reasons. Among the reasons is that efficiency has reached a plateau. Any financial incentive to replace plants is absent. Efforts should be directed toward the development and application of new technologies, rather than retrofitting yesterday's pollution control technology or disrupting the mining industry to control existing plants.

The approach being taken by Kentucky has been recommended for adoption as international policy by the Administrations of Canada and the United States. Canadian Prime Minister Mulroney and President Reagan have endorsed the recommendations of acid rain envoys William Davis and Drew Lewis calling for a $5 billion program to demonstrate new processes for using coal more cleanly. We agree with the recommendation and urge Congressional support of an expanded Clean Coal Technology Program.

In conclusion, I urge the cosponsors of this bill to take another look at what H.R. 4567 would actually do, and what it would not do, and compare this to how it is being portrayed. Further, I encourage serious consideration of the approach Kentucky has already initiated at the state level and which has gained support at the international level: acceleration of the development and application of new clean coal technologies.

Sincerely,

Wendell Ford
Wendell H. Ford

The Honorable Henry A. Waxman
Chairman
Subcommittee on Health
and the Environment
Committee on Energy and Commerce
U. S. House of Representatives
Washington, D. C. 20515

Enclosure

Table 1

U.S. DEMONSTRATED RESERVE BASE BY SULFUR CATEGORY
(in millions of tons)

State	lbs SO_2 per million Btu			
	less than 0.9	0.9 to 1.2	more than 1.2	Total
Kentucky	0	10,210	24,030	34,240
Virginia	784	1,469	1,285	3,538
West Virginia	3,407	13,724	22,854	39,985
Other Eastern U.S.	21	2,746	133,747	136,514
Subtotal	4,212	28,149	181,916	214,277
Alaska	5,805	18	332	6,155
Colorado	7,800	2,212	1,363	16,215
Montana	84,247	32,786	3,436	120,469
New Mexico	1,277	508	2,756	4,541
Wyoming	33,527	8,560	27,927	70,014
Other Western U.S.	1,826	5,677	40,222	47,725
Subtotal	134,482	49,761	76,036	260,279
Total U.S.	138,694	77,909	257,952	474,556

Source: Acid Rain and Transported Air Pollutants, Office of Technology Assessment, Washington, D.C., June 1984

Table 2

KENTUCKY COAL RESOURCES IN COMPLIANCE WITH VARIOUS SULFUR DIOXIDE EMISSION STANDARDS

Compliance Standard (lbs SO_2 per million Btu)	Eastern Kentucky	Western Kentucky	Total Kentucky
	(as a percentage of coal resources)		
2.0	70	5	43
1.6	61	4	37
1.4	56	3	33
1.2	43	2	26
1.0	20	1	15
0.8	5	0	4
0.6	1	0	1

Source: J. C. Cobb, J. C. Currens, H. G. Enoch, Compliance Coal Resources in Kentucky, Kentucky Geological Survey, Lexington, Kentucky, 1982.

Senator **Ford**. I thank the chairman, and I look forward to hearing from the Democratic leader.

The **Chairman**. Our first witness this morning is the Honorable Robert C. Byrd, U.S. Senator from West Virginia, and I do not think I need to belabor the subject that is so well known that this Senator, who is our leadoff witness, is perhaps one of the leading proponents of clean coal technology and of the program which is underway today.

We are very glad to have you appear before us this morning.

STATEMENT OF HON. ROBERT C. BYRD, A U.S. SENATOR FROM THE STATE OF WEST VIRGINIA

Senator **Byrd**. Mr. Chairman, I thank you, and I thank you for conducting these hearings. I appreciate your reference to my longtime interest in clean coal technology, and it has been through working with you and others on the Appropriations Committee that we have had to fight this battle, and we have been successful up to this point, not quite as much as we would like to have been, but nevertheless we have stood our ground, and I am proud that we were able to get $400 million appropriated over a 3-year period of the $750 million that was authorized in the original legislation.

I also thank Senator Ford for his letter, to which he referred as being a letter which he liked, and one which probably the recipient may not have liked quite so well. I have not read the letter, but any letter that Senator Ford would write on this subject I would be fully supportive of sight unseen. He comes from the neighboring State of ours, the State of Kentucky, and they have similar problems, common problems with us, with ours.

And I congratulate both you and Senator Ford on the leadership that you have shown and that the committee has shown in this field, development of clean coal technology which will increase the use of coal and at the same time cause it to be burned in a manner that will be environmentally acceptable.

I am also pleased to see the lineup of witnesses, all of whom are outstanding witnesses and certainly have everything to recommend them as witnesses. In particular I am glad to note that Michael Greer, the chairman of the West Virginia Public Service Commission, is on the list of witnesses for today. I am sure that he will be in a position to state to the committee what the impact would be on the ratepayers, industrial, commercial, and residential ratepayers in West Virginia should legislation such as H.R. 4567 be enacted.

I am also sure that he will be in a position to state that the enactment of that legislation at this time would certainly discourage the use of clean coal technology, and would discourage the private sector from advancing the proposals that otherwise will be advanced and even those which have already been advanced are going to require a considerable number of years, I am sure, in their full implementation and demonstration, and then their commercial and industrial use.

I commend Senator Rockefeller, our former Governor, who is a member of this committee, and who is certainly in a good position to testify with respect to West Virginia, its problems, problems that would be impacted on the coal industry and on the people who work in that industry, and on the associated industries, the railroad industry and others, should legislation such as H.R. 4567 become a reality.

That legislation has developed a considerable amount of momentum on the other side. I hope that these hearings will be instrumental in giving balance to the testimony that may have been given in support of that legislation, and not only giving balance to but also giving a true sense of reality to the facts as to the economic and other results that would adversely, and I am speaking of adverse results that would be concommitant with the passage of this legislation.

So, I thank you again, Mr. Chairman. These hearings are important, and they are timely for a number of reasons. First, the President has endorsed a $5 billion Clean Coal Technology Demonstration Program cost shared on a 50–50 basis with industry as the cornerstone of an approach to the acid rain issue. The President's endorsement gave greater visbility to efforts to develop new and advanced clean coal technologies. However, his endorsement also explicitly linked the development and use of such technologies to the acid rain issue.

I should emphasize that there are important differences between the $5 billion clean coal program recommended and the report of the special envoys on acid rain and the clean coal technology program enacted by the Congress in 1984 as Public Law No. 98–473 authorizing $750 million for the program. These differences can be summarized briefly as noting that unlike the initiative recommended in the report of the special envoys on acid rain, the Clean Coal Technology Program is not, and I emphasize not, primarily directed to addressing the acid rain issue. Rather, it is directed to the enhancement and the expansion of the use of coal.

Nevertheless, the linkage, and that linkage is important, the linkage of the acid rain issue and clean coal technology in general raises several questions which should be addressed regarding the relationship of the congressionally enacted Clean Coal Program and the larger initiative endorsed by the President.

For example, how does the administration intend to honor its commitment recently made to the Canadian Government? Does the administration view the December 1985, clean coal technology appropriation of $400 million as a down payment on the $5 billion initiative proposed by the President? Does the administration intend to request the appropriation of the remaining $350 million authorized in Public Law 98–473 for the Clean Coal Technology Program? Does the administration intend to request additional funds in the 1987 or 1988 budgets over and above the authorized $750 million to implement the Clean Coal Program endorsed by the President?

Clarification of these issues has taken on a degree of urgency in the aftermath of the recent action of the House Subcommittee on Health and Environment in reporting to the full committee H.R. 4567. That legislation, if enacted, would have a devastating impact on the economy of West Virginia and other coal producing and coal consuming States. United Mineworkers of America estimates that H.R. 4567 would cost over 7,200 jobs in West Virginia in the coal mining industry of my State, and would result in total economic losses in West Virginia of over $690 million annually.

The 7,200 jobs are not just in the industry alone. That would not be the result directly of the legislation were it to be passed. But in the associated industries and the accumulated effect, the result would be 7,200 plus, over 7,200 jobs that would be lost, and I have a table here which I can supply for the record which provides this information not only for the State of West Virginia but also for other States as well.

In addition, H.R. 4567 raises questions regarding the implications of such legislation for the future of the Clean Coal Technology Program and for the adoption of technologies by industry. For example, what would be the prospect for industry adoption of clean coal technologies under the provisions of H.R. 4567? I think it is obvious that the passage of that legislation prior to the enactment of this program that we are talking about, the Clean Coal Technology Program, and by enactment I do not mean the legislative enactment—that is already in the past, and appropriations have been made therefore. What I am talking about is the implementation of the program, and 51 proposals have already been submitted from the private sector. The Department has refined those and has reduced those to 39, I believe. On August 1 the Department will indicate which of those proposals it wishes to enter into contractual obligations on.

So, Mr. Chairman, I would emphasize—I know that Senator Rockefeller can do so on the committee at length—the impact that acid rain legislation that is making its way through the subcommittee, at least, of the House, which is chaired by Mr. Waxman, the impact it would have on areas like northern West Virginia. I know some of our people have said, well, in southern West Virginia, where we have low sulfur coal, we will be able to absorb those jobs that would be lost in northern West Virginia, where we have the high sulfur coal.

Well, of course, that is a fantasy, because not only would those jobs that are lost in northern West Virginia in the high sulfur region not be absorbed in southern West Virginia because the first people who would come back to work, who would be brought back to work by virtue of any increased production of low sulfur coal, would be the coal miners in southern West Virginia who have lost their jobs. And then to say that, in addition, that the production of low sulfur coal in West Virginia would balance off the impact, economic impact not only in jobs but the economy, taxes, and so on, in northern West Virginia, to say that it would balance it off is a joke, because what happens to the communities, which are going to become ghost towns, the baker, the butcher, and the candlestick maker, and the gas station operator, and all of the associated jobs that go along with a thriving and healthy coal industry?

So, it is a joke to pretend that the low sulfur coal regions in my State alone would be able to absorb the jobs that would be lost in the high sulfur regions, and I would say that what we would see in the wake of this legislation would be ghost towns, mining communities that are shut down, the windows of mining community houses boarded up, high unemployment compensation payments, more food stamps, and people who would lose all hope of ever being able to resume work in the coal mines.

So, Mr. Chairman, the results are not to be lightly taken and just so easily brushed away as some would attempt to by advancing the kind of arguments and cases that I have referred to. The hearings you have scheduled could also help to ensure the success of the Clean Coal Technology Program for which $400 million was appropriated by the Congress last year.

The Department of Energy got the Clean Coal Program off to a shaky start. This may have had a chilling effect on the industry response to the DOE Clean Coal Program opportunity notice. For example, in view of the potential for retrofitting existing facilities, it would appear that retrofit technologies may be underrepresented in a proposal submitted to the Department this past April. This is unfortunate, given the opportunities for retrofitting existing facilities with cleaner, more efficient clean coal technologies and the implications of such opportunities with regard to the acid rain issue.

In the last decade or so there have been a number of economic, regulatory, and other developments which have created significant disincentives for electric utilities to commit financial resources to the construction of new generating capacity. Indeed, rather than undertake new construction projects, many electric utilities are making plans to extend the service life of existing generating facilities beyond their original design lifetimes, which are usually 30 to 40 years.

According to the Energy Information Administration, by 1995 over 60 percent of all coal-fired powerplants, accounting for about one-quarter of total coal-fired generating capacity, will be more than 30 years old, and by comparison, in 1985 approximately 10 percent of such facilities were more than 30 years old. Therefore it is clear that there is significant opportunity for the adoption of clean coal technologies for retrofit application.

The extent to which utilities implement plans to extend the life of existing facilities and the extent to which clean coal technologies are an integral part of those plans could have implications for future emissions trends, and I was pleased to hear you emphasize this aspect of your hearings in your opening statement.

The Clean Air Act is working, Mr. Chairman. We all want to continue the progress made to date under the Clean Air Act. For example, according to EPA's 1986 report on national emissions trends, and I note that you have here today the Honorable Lee Thomas, who is the Administrator of the Environmental Protection Agency, who will testify. According to EPA's 1986 report on national emissions trends, between 1973 and 1983 emissions of sulfur dioxide declined 28 percent. Meanwhile, according to the National Coal Association, the use of coal by the electric utility industry during that same 1973–1983 period increased 68 percent.

In fact, according to EPA, in 1984 there were only 63 counties in the entire United States not in compliance with Clean Air Act standards for sulfur dioxide. In view of the enormous economic cost of acid rain control legislation, it seems to me that the burden of proof is upon those who seek to so drastically change the Clean Air Act status quo through the impocition of acid rain regulatory programs as required by H.R. 4567.

To date, I do not believe that the case has been made. Many times in the past, Mr. Chairman, I have questioned the wisdom of pursuing regulatory responses to the acid rain issue before the scientific evidence is available to assess the appropriateness and the effectiveness of such approaches. For example, the environmental damage to lakes alleged to have been caused by acid rain is not as ubiquitous as once assumed. Although the geographic extent of any damage is currently uncertain, it would appear that documented instances of damage to surface waters are limited to relatively few high elevation lakes in the Adirondack Mountains and New England with little buffering capacity.

In addition, the recently published report of the National Academy of Sciences indicates that over the past several decades many lakes in Wisconsin, New Hampshire, and New York have decreased in pH the percentage of hydrogen lands and alkalinity, and many have increased in pH and alkalinity. There may be other aquatic resources considered to be at risk to damage from acid deposition, but there is little scientific information about the dose-response relationship, that is, the rate of change in the status of lakes, in response to any given change in the level of deposition.

The dose response issue is just one of the key areas for which scientific information must be developed if policymakers are to have any confidence that the imposition of a costly new regulatory program will be effective in achieving any of the purported environmental results.

Finally, let me say that acid deposition has been blamed by some for the increased mortality of red spruce in eastern North America as well as the decline of forests at particular locations in Europe, but little is known about the causes of this serious environmental problem, and as the National Academy of Sciences recently concluded, "There is no new indication that acidic deposition is an important factor in the red spruce decline."

Mr. Chairman, I believe that the available scientific evidence regarding the environmental effects of acid deposition clearly indicates that a crisis situation does not now exist. In fact, a report by the United States Geological Survey analyzing precipitation chemistry data from 1978 to 1983 suggests that the situation has improved. According to that report, wet sulfate and nitrate concentrations have declined, but sulfate showed the largest decreases in concentration per year of all the ions tested.

In other words, Mr. Chairman, the Clean Air Act is working. In addition, Congress has yet to receive and consider the final report of the interagency task force required by the Energy Security Act of 1980. The findings of that group will be critical in determining the appropriate course of action. In the meantime, we should not act precipitously. If some of the acid rain control legislation currently being considered were enacted, there would be very serious implications for the use of coal, and indeed, that is the crucial energy policy issue confronting the Congress.

What policy is this Nation going to pursue regarding the use of coal? It is apparent that coal will play an increasingly prominent role in providing for this Nation's energy needs for the foreseeable future. In 1985 the domestic electric utility industry consumed about 693 million tons of coal, which accounted for about 56 percent of all electricity generated in the United States.

By 1995, the Energy Information Administration estimates that coal-fired electric power generation will continue to account for about 56 percent of all electric generation. The utility coal consumption by 1995 is expected to increase about 27 percent above 1985 levels as demand for electricity grows. In the longer term, the EIA estimates that by the year 2010, coal-fired electric power generation could account for about 60 percent of all electric generation, and utility coal consumption could increase about 95 percent above 1985 levels.

The commercial adoption of clean coal technologies for new electric generating capacity and retrofit applications to meet the Nation's future energy needs together form the key to promoting the more efficient use of the Nation's most abundant fossil energy resource and to continuing in the progress achieved to date under the Clean Air Act. The implementation of the Clean Coal Technology Program is the first major step in the effort to expand the use of coal in an environmentally acceptable manner.

Unfortunately, a number of issues are yet to be addressed and resolved. For example, should there be a second phase to the Clean Coal Program involving a project solicitation which would emphasize retrofittable technologies? What regulatory and administrative measures can the Federal Government initiate to promote the use of such technologies?

What are the implications of acid rain legislation for the adoption of clean coal technologies by industry? If acid rain legislation were enacted, to what extent would electric utilities choose fuel switching and scrubbers rather than clean coal technologies to meet emissions reduction requirements?

If acid rain legislation such as H.R. 4567 were enacted, I do not believe that the promise of the Clean Coal Technology Program would be realized. The mid-1990's deadline imposed in the House bill for achieving the stringent emissions standards required would force utilities to decide between installing scrubber technology, fuel switching, or retiring generating capacity.

Many clean coal technologies will not be an option because their demonstration may have only been completed by the 1990's. The unique opportunities represented by retrofit applications would be lost because utilities would be very reluctant to gamble on technologies which have not been adequately—which will not have been adequately demonstrated by that time.

These are important issues on which additional hearings may be useful. That is your call to make, Mr. Chairman, in the judgment of yourself and the committee.

I believe that the Clean Coal Technology Program represents the first bright glimmer of a new day for the future of coal. But there is much to do if we are to ensure that coal becomes the jewel in the crown of the Nation's energy future.

Mr. Chairman, in summation, I hope that my testimony has made the following three major points: One, the Clean Air Act is working in achieving emissions reductions in a manner which does not cause severe economic disruption in coal-producing and coal-consuming States.

Two, the Clean Coal Technology Program is a unique opportunity to expand and enhance the use of coal in an environmentally acceptable manner.

And three, the opportunities to expand and enhance the use of coal through the use of clean coal technologies will be lost if acid rain legislation is enacted.

Mr. Chairman, that concludes my statement.

[The prepared statement and additional material submitted by Senator Byrd follow:]

HEARING: CLEAN COAL/ACID RAIN

TESTIMONY OF SENATOR ROBERT C. BYRD
OVERSIGHT HEARING ON
CLEAN COAL TECHNOLOGY AND
STRATEGIES FOR ACID RAIN CONTROL,
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
WASHINGTON, D.C.
JUNE 9, 1986

MR. CHAIRMAN, FIRST LET ME THANK YOU FOR SCHEDULING THESE HEARINGS ON THE CLEAN COAL TECHNOLOGY PROGRAM AND STRATEGIES FOR ACID RAIN CONTROL.

THESE HEARINGS ARE IMPORTANT AND TIMELY FOR A NUMBER OF REASONS. FIRST, THE PRESIDENT HAS ENDORSED A $5 BILLION CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM, COST-SHARED ON A 50/50 BASIS WITH INDUSTRY, AS THE CORNERSTONE OF AN APPROACH TO THE ACID RAIN ISSUE. THE PRESIDENT'S ENDORSEMENT GAVE GREATER VISIBILITY TO EFFORTS TO DEVELOP

NEW AND ADVANCED COAL TECHNOLOGIES. HOWEVER, HIS ENDORSEMENT ALSO EXPLICITLY LINKED THE DEVELOPMENT AND USE OF SUCH TECHNOLOGIES TO THE ACID RAIN ISSUE.

I SHOULD EMPHASIZE THAT THERE ARE IMPORTANT DIFFERENCES BETWEEN THE $5 BILLION CLEAN COAL PROGRAM RECOMMENDED IN THE REPORT OF THE SPECIAL ENVOYS ON ACID RAIN AND THE CLEAN COAL TECHNOLOGY PROGRAM ENACTED BY THE CONGRESS IN 1984 AS PUBLIC LAW NUMBER 98-473, AUTHORIZING $750 MILLION FOR THE PROGRAM. THESE DIFFERENCES CAN BE SUMMARIZED VERY BRIEFLY BY NOTING THAT, UNLIKE THE INITIATIVE RECOMMENDED IN THE REPORT OF THE SPECIAL ENVOYS ON ACID RAIN, THE CLEAN COAL TECHNOLOGY PROGRAM IS NOT PRIMARILY DIRECTED TO ADDRESSING THE ACID RAIN ISSUE. RATHER, IT IS DIRECTED TO THE ENHANCEMENT AND EXPANSION OF THE USE OF COAL.

NEVERTHELESS, THE LINKAGE OF THE ACID RAIN ISSUE AND CLEAN COAL TECHNOLOGY IN GENERAL RAISES SEVERAL QUESTIONS WHICH SHOULD BE ADDRESSED REGARDING THE RELATIONSHIP OF THE CONGRESSIONALLY-ENACTED CLEAN COAL PROGRAM AND THE LARGER

INITIATIVE ENDORSED BY THE PRESIDENT. FOR EXAMPLE, HOW DOES THE ADMINISTRATION INTEND TO HONOR ITS COMMITMENT RECENTLY MADE TO THE CANADIAN GOVERNMENT? DOES THE ADMINISTRATION VIEW THE DECEMBER, 1985 CLEAN COAL TECHNOLOGY APPROPRIATION OF $400 MILLION AS A "DOWNPAYMENT" ON THE $5 BILLION INITIATIVE PROPOSED BY THE PRESIDENT? DOES THE ADMINISTRATION INTEND TO REQUEST THE APPROPRIATION OF THE REMAINING $350 MILLION AUTHORIZED IN P.L. 98-473 FOR THE CLEAN COAL TECHNOLOGY PROGRAM? DOES THE ADMINISTRATION INTEND TO REQUEST ADDITIONAL FUNDS OVER AND ABOVE THE AUTHORIZED $750 MILLION TO IMPLEMENT THE CLEAN COAL PROGRAM ENDORSED BY THE PRESIDENT?

CLARIFICATION OF THESE ISSUES HAS TAKEN ON A DEGREE OF URGENCY IN THE AFTERMATH OF THE RECENT ACTION OF THE HOUSE SUBCOMMITTEE ON HEALTH AND ENVIRONMENT IN REPORTING TO THE FULL COMMITTEE H.R. 4567. THAT LEGISLATION, IF ENACTED, WOULD HAVE A DEVASTATING IMPACT ON THE ECONOMY OF WEST VIRGINIA AND OTHER COAL-PRODUCING AND COAL-CONSUMING STATES.

THE UNITED MINE WORKERS ESTIMATES THAT H.R. 4567 WOULD COST OVER 7,200 JOB IN WEST VIRGINIA IN THE COAL MINING INDUSTRY OF MY STATE, AND RESULT IN TOTAL ECONOMIC LOSSES IN WEST VIRGINIA OF OVER $690 MILLION ANNUALLY. IN ADDITION, H.R. 4567 RAISES QUESTIONS REGARDING THE IMPLICATIONS OF SUCH LEGISLATION FOR THE FUTURE OF THE CLEAN COAL TECHNOLOGY PROGRAM, AND FOR THE ADOPTION OF SUCH TECHNOLOGIES BY INDUSTRY. FOR EXAMPLE, WHAT WOULD BE THE PROSPECTS FOR INDUSTRY ADOPTION OF CLEAN COAL TECHNOLOGIES UNDER THE PROVISIONS OF H.R. 4567?

MR. CHAIRMAN, THE HEARINGS YOU HAVE SCHEDULED COULD ALSO HELP ENSURE THE SUCCESS OF THE CLEAN COAL TECHNOLOGY PROGRAM FOR WHICH $400 MILLION WAS APPROPRIATED BY THE CONGRESS LAST YEAR. THE DEPARTMENT OF ENERGY GOT THE CLEAN COAL PROGRAM OFF TO A SHAKY START. THIS MAY HAVE HAD A "CHILLING EFFECT" ON THE INDUSTRY RESPONSE TO THE DOE CLEAN COAL PROGRAM OPPORTUNITY NOTICE. FOR EXAMPLE, IN VIEW OF THE POTENTIAL FOR RETROFITTING EXISTING FACILITIES, IT WOULD

APPEAR THAT RETROFIT TECHNOLOGIES MAY BE UNDER-REPRESENTED IN THE PROPOSALS SUBMITTED TO THE DEPARTMENT THIS PAST APRIL. THIS IS UNFORTUNATE GIVEN THE OPPORTUNITIES FOR RETROFITTING EXISTING FACILITIES WITH CLEANER, MORE EFFICIENT, CLEAN COAL TECHNOLOGIES, AND THE IMPLICATIONS OF SUCH OPPORTUNITIES WITH REGARD TO THE ACID RAIN ISSUE.

IN THE LAST DECADE OR SO, THERE HAVE BEEN A NUMBER OF ECONOMIC, REGULATORY, AND OTHER DEVELOPMENTS WHICH HAVE CREATED SIGNIFICANT DISINCENTIVES FOR ELECTRIC UTILITIES TO COMMIT FINANCIAL RESOURCES TO THE CONSTRUCTION OF NEW GENERATING CAPACITY. INDEED, RATHER THAN UNDERTAKE NEW CONSTRUCTION PROJECTS, MANY ELECTRIC UTILITIES ARE MAKING PLANS TO EXTEND THE SERVICE LIFE OF EXISTING GENERATING FACILITIES BEYOND THEIR ORIGINAL DESIGN LIFETIMES, WHICH ARE USUALLY 30 TO 40 YEARS. ACCORDING TO THE ENERGY INFORMATION ADMINISTRATION (EIA), BY 1995 OVER 60% OF ALL COAL-FIRED POWERPLANTS -- ACCOUNTING FOR ABOUT ONE-QUARTER OF TOTAL COAL-FIRED GENERATING CAPACITY -- WILL BE MORE THAN 30 YEARS

OLD. BY COMPARISON, IN 1985 APPROXIMATELY 10% OF SUCH FACILITIES WERE MORE THAN 30 YEARS OLD.

THUS, IT IS CLEAR THAT THERE IS SIGNIFICANT OPPORTUNITY FOR THE ADOPTION OF CLEAN COAL TECHNOLOGIES FOR RETROFIT APPLICATIONS. THE EXTENT TO WHICH UTILITIES IMPLEMENT PLANS TO EXTEND THE LIFE OF EXISTING FACILITIES, AND THE EXTENT TO WHICH CLEAN COAL TECHNOLOGIES ARE AN INTEGRAL PART OF THOSE PLANS, COULD HAVE IMPLICATIONS FOR FUTURE EMISSIONS TRENDS.

MR. CHAIRMAN, THE CLEAN AIR ACT IS WORKING, AND WE ALL WANT TO CONTINUE THE PROGRESS MADE TO DATE UNDER THE CLEAN AIR ACT. FOR EXAMPLE, ACCORDING TO EPA'S 1986 REPORT ON NATIONAL EMISSIONS TRENDS, BETWEEN 1973 AND 1983, EMISSIONS OF SULFUR DIOXIDE DECLINED 28%. MEANWHILE, ACCORDING TO THE NATIONAL COAL ASSOCIATION, THE USE OF COAL BY THE ELECTRIC UTILITY INDUSTRY DURING THAT SAME 1973-1983 PERIOD INCREASED 68%. IN FACT, ACCORDING TO EPA, IN 1984 THERE WERE ONLY 63 COUNTIES IN THE ENTIRE UNITED STATES NOT IN COMPLIANCE WITH CLEAN AIR ACT STANDARDS FOR SULFUR DIOXIDE.

IN VIEW OF THE ENORMOUS ECONOMIC COSTS OF ACID RAIN CONTROL LEGISLATION, IT SEEMS TO ME THAT THE BURDEN OF PROOF IS UPON THOSE WHO SEEK TO SO DRASTICALLY CHANGE THE CLEAN AIR ACT STATUS QUO THROUGH THR IMPOSITION OF ACID RAIN REGULATORY PROGRAMS, AS REQUIRED BY H.R. 4567. TO DATE, I DO NOT BELIEVE THAT THE CASE HAS BEEN MADE.

MR. CHAIRMAN, MANY TIMES IN THE PAST I HAVE QUESTIONED THE WISDOM OF PURSUING REGULATORY RESPONSES TO THE ACID RAIN ISSUE BEFORE THE SCIENTIFIC EVIDENCE IS AVAILABLE TO ASSESS THE APPROPRIATENESS AND EFFECTIVENESS OF SUCH APPROACHES. FOR EXAMPLE, THE ENVIRONMENTAL DAMAGE TO LAKES ALLEGED TO HAVE BEEN CAUSED BY ACID RAIN IS NOT AS UBIQUITOUS AS ONCE ASSUMED. ALTHOUGH THE GEOGRAPHIC EXTENT OF ANY DAMAGE IS CURRENTLY UNCERTAIN, IT WOULD APPEAR THAT DOCUMENTED INSTANCES OF DAMAGE TO SURFACE WATERS ARE LIMITED TO RELATIVELY FEW HIGH ELEVATION LAKES IN THE ADIRONDACK MOUNTAINS AND NEW ENGLAND WITH LITTLE BUFFERING CAPACITY.

IN ADDITION, THE RECENTLY PUBLISHED REPORT OF THE NATIONAL ACADEMY OF SCIENCES INDICATES THAT, OVER THE PAST SEVERAL DECADES, MANY LAKES IN WISCONSIN, NEW HAMPSHIRE, AND NEW YORK HAVE "DECREASED IN PH (THE PERCENT OF HYDROGEN IONS) AND ALKALINITY AND MANY HAVE INCREASED IN PH AND ALKALINITY."

THERE MAY BE OTHER AQUATIC RESOURCES CONSIDERED TO BE "AT RISK" TO DAMAGE FROM ACID DEPOSITION. HOWEVER, THERE IS LITTLE SCIENTIFIC INFORMATION ABOUT THE "DOSE-RESPONSE" RELATIONSHIP -- THAT IS, THE RATE OF CHANGE IN THE STATUS OF LAKES IN RESPONSE TO ANY GIVEN CHANGE IN THE LEVEL OF DEPOSITION. THE DOSE-RESPONSE ISSUE IS JUST ONE OF THE KEY AREAS FOR WHICH SCIENTIFIC INFORMATION MUST BE DEVELOPED IF POLICY-MAKERS ARE TO HAVE ANY CONFIDENCE THAT THE IMPOSITION OF A COSTLY NEW REGULATORY PROGRAM WILL BE EFFECTIVE IN ACHIEVING ANY OF THE PURPORTED ENVIRONMENTAL RESULTS.

FINALLY, LET ME POINT OUT THAT ACID DEPOSITION HAS BEEN BLAMED BY SOME FOR THE INCREASED MORTALITY OF RED SPRUCE IN

EASTERN NORTH AMERICA, AS WELL AS THE DECLINE OF FORESTS AT PARTICULAR LOCATIONS IN EUROPE. BUT LITTLE IS KNOWN ABOUT THE CAUSES OF THIS SERIOUS ENVIRONMENTAL PROBLEM, AND, AS THE NATIONAL ACADEMY OF SCIENCES REPORT RECENTLY CONCLUDED, "THERE IS NOW NO INDICATION THAT ACIDIC DEPOSITION IS AN IMPORTANT FACTOR IN THE RED SPRUCE DECLINE."

MR. CHAIRMAN, I BELIEVE THE AVAILABLE SCIENTIFIC EVIDENCE REGARDING THE ENVIRONMENTAL EFFECTS OF ACID DEPOSITION CLEARLY INDICATES THAT A CRISIS SITUATION DOES NOT EXIST. IN FACT, A REPORT BY THE UNITED STATES GEOLOGICAL SURVEY ANALYZING PRECIPITATION CHEMISTRY DATA FROM TO 1978 TO 1983 SUGGESTS THAT THE SITUATION HAS IMPROVED. ACCORDING TO THAT REPORT, WET SULFATE AND NITRATE CONCENTRATIONS HAVE DECLINED, BUT "SULFATE SHOWED THE LARGEST DECREASES IN CONCENTRATION PER YEAR OF ALL THE IONS TESTED." IN OTHER WORDS, MR. CHAIRMAN, THE CLEAN AIR ACT IS WORKING.

IN ADDITION, CONGRESS HAS YET TO RECEIVE AND CONSIDER THE FINAL REPORT OF THE INTERAGENCY TASK FORCE REQUIRED BY THE ENERGY SECURITY ACT OF 1980. THE FINDINGS OF THAT GROUP WILL BE CRITICAL IN DETERMINING THE APPROPRIATE COURSE OF ACTION. IN THE MEANTIME, WE SHOULD NOT ACT "PRECIPITOUSLY." IF SOME OF THE ACID RAIN CONTROL LEGISLATION CURRENTLY BEING CONSIDERED WERE ENACTED, THERE WOULD BE VERY SERIOUS IMPLICATIONS FOR THE USE OF COAL. INDEED, THAT IS THE CRUCIAL ENERGY POLICY ISSUE CONFRONTING THE CONGRESS -- WHAT POLICY IS THIS NATION GOING TO PURSUE REGARDING THE USE OF COAL?

IT IS APPARENT THAT COAL WILL PLAY AN INCREASINGLY PROMINENT ROLE IN PROVIDING FOR THIS NATION'S ENERGY NEEDS FOR THE FORESEEABLE FUTURE. IN 1985, THE DOMESTIC ELECTRIC UTILITY INDUSTRY CONSUMED ABOUT 693 MILLION TONS OF COAL, WHICH ACCOUNTED FOR ABOUT 56% OF ALL ELECTRICITY GENERATED IN THE UNITED STATES. BY 1995, THE ENERGY INFORMATION ADMINISTRATION ESTIMATES THAT COAL-FIRED ELECTRIC POWER

GENERATION WILL CONTINUE TO ACCOUNT FOR ABOUT 56% OF ALL ELECTRIC GENERATION, BUT UTILITY COAL CONSUMPTION BY 1995 IS EXPECTED TO INCREASE ABOUT 27% ABOVE 1985 LEVELS AS DEMAND FOR ELECTRICITY GROWS. IN THE LONGER-TERM, THE EIA ESTIMATES THAT BY THE YEAR 2010, COAL-FIRED ELECTRIC POWER GENERATION COULD ACCOUNT FOR ABOUT 60% OF ALL ELECTRIC GENERATION, AND UTILITY COAL CONSUMPTION COULD INCREASE ABOUT 95% ABOVE 1985 LEVELS.

THE COMMERCIAL ADOPTION OF CLEAN COAL TECHNOLOGIES FOR NEW ELECTRIC GENERATING CAPACITY AND RETROFIT APPLICATIONS TO MEET THE NATION'S FUTURE ENERGY NEEDS TOGETHER FORM THE KEY TO PROMOTING THE MORE EFFICIENT USE OF THE NATION'S MOST ABUNDANT FOSSIL ENERGY RESOURCE, AND TO CONTINUING THE PROGRESS ACHIEVED TO DATE UNDER THE CLEAN AIR ACT. THE IMPLEMENTATION OF THE CLEAN COAL TECHNOLOGY PROGRAM IS THE FIRST MAJOR STEP IN THE EFFORT TO EXPAND THE USE OF COAL IN AN ENVIRONMENTALLY ACCEPTABLE MANNER.

UNFORTUNATELY, A NUMBER OF ISSUES ARE YET TO BE ADDRESSED AND RESOLVED. FOR EXAMPLE, SHOULD THERE BE A SECOND PHASE TO THE CLEAN COAL PROGRAM INVOLVING A PROJECT SOLICITATION WHICH WOULD EMPHASIZE RETROFITABLE TECHNOLOGIES? WHAT REGULATORY AND ADMINISTRATIVE MEASURES CAN THE FEDERAL GOVERNMENT INITIATE TO PROMOTE THE USE OF SUCH TECHNOLOGIES? WHAT ARE THE IMPLICATIONS OF ACID RAIN LEGISLATION FOR THE ADOPTION OF CLEAN COAL TECHNOLOGIES BY INDUSTRY? IF ACID RAIN LEGISLATION WERE ENACTED, TO WHAT EXTENT WOULD ELECTRIC UTILITIES CHOOSE FUEL-SWITCHING AND SCRUBBERS, RATHER THAN CLEAN COAL TECHNOLOGIES, TO MEET EMISSIONS REDUCTION REQUIREMENTS?

IF ACID RAIN LEGISLATION, SUCH AS H.R. 4567, WERE ENACTED, I DO NOT BELIEVE THAT THE PROMISE OF THE CLEAN COAL TECHNOLOGY PROGRAM WOULD BE REALIZED. THE MID-1990S DEADLINE IMPOSED IN THE HOUSE BILL FOR ACHIEVING THE STRINGENT EMISSIONS STANDARDS REQUIRED WOULD FORCE UTILITIES TO DECIDE BETWEEN INSTALLING SCRUBBER TECHNOLOGY, FUEL

SWITCHING, AND RETIRING GENERATING CAPACITY. MANY CLEAN COAL TECHNOLOGIES WILL NOT BE AN OPTION, BECAUSE THEIR DEMONSTRATION MAY HAVE ONLY BEEN COMPLETED IN THE 1990S. THE UNIQUE OPPORTUNITIES REPRESENTED BY RETROFIT APPLICATIONS WOULD BE LOST BECAUSE UTILITIES WOULD BE VERY RELUCTANT TO GAMBLE ON TECHNOLOGIES WHICH HAVE NOT BEEN ADEQUATELY DEMONSTRATED.

MR. CHAIRMAN, THESE ARE IMPORTANT ISSUES, ON WHICH ADDITIONAL HEARINGS WOULD BE USEFUL.

I BELIEVE THAT THE CLEAN COAL TECHNOLOGY PROGRAM REPRESENTS THE FIRST BRIGHT GLIMMER OF A NEW DAY FOR THE FUTURE OF COAL. BUT THERE IS MUCH TO DO IF WE ARE TO ENSURE THAT COAL BECOMES THE JEWEL IN THE CROWN OF THE NATION'S ENERGY FUTURE.

MR. CHAIRMAN, THAT CONCLUDES MY STATEMENT. I WILL BE GLAD TO ANSWER ANY QUESTIONS.

EMPLOYMENT AND ECONOMIC IMPACTS OF H.R. 4567

States	Total Tons Of Coal Displaced (x10^3) 1/	Average Annual Tonnage Output Per Coal Mining Industry Employee 2/	Coal Mining Industry Employee Job Losses	Total Annual Coal Mining Industry Employee Economic Losses (x10^6) 3/	Indirect Economic Losses Multiplier 4/	Total Annual Indirect Economic Losses (x10^6)	Total Annual Economic Losses (x10^6)
Alabama	3,375	2,949	1,144	$ 37.9	2.44	$ 92.6	$ 130.5
Illinois	13,515	3,484	3,879	128.4	2.74	351.4	479.8
Indiana	7,800	4,930	1,582	52.6	1.57	82.8	135.3
Kansas	500	4,638	108	3.6	3.23	11.5	15.1
Kentucky	28,580	3,791	7,540	249.7	2.28	569.5	819.1
Maryland	1,265	4,100	309	10.2	5.89	59.9	70.0
Missouri	3,650	4,111	888	29.4	2.90	85.4	114.8
Ohio	17,575	3,494	5,030	166.0	1.76	292.1	458.1
Oklahoma	725	3,075	236	7.8	2.71	21.1	28.9
Pennsylvania	24,750	2,917	8,484	280.8	2.25	630.9	911.7
Tennessee	1,775	2,688	660	21.8	2.34	51.0	72.7
Virginia	3,345	2,786	1,201	40.1	3.97	159.0	199.1
West Virginia	22,695	3,150	7,206	239.1	1.89	451.3	690.4
TOTAL	129,550		38,267	$1,267.2		$2,858.4	$4,125.6

1/ Coal consumption and coal quality were examined for every coal fired power plant (greater than 50 megawatts) to estimate 1984 sulfur dioxide emissions. SO_2 reductions necessary by 1997 were calculated for each state based on a statewide average emission rate of 1.7 lbs./mm Btu. (Note: The actual average emission rate would be lower because standards must be met on a monthly basis).

A least-cost strategy to meet emission reductions was determined for each utility plant. The major assumptions in the analysis were:

Scrubber capital cost:	$300/kw
Scrubber O & M cost:	4.5 mills/kwh
Switching capital cost:	$21/kw
Compliance coal cost:	20% price increase
Estimated life of plant:	20 years

Current coal supplies were reviewed for plants that would utilize fuel switching. Non-compliance coal supplies were assumed to be displaced.

2/ U.S. Department of Labor, Mine Safety and Health Administration, Mine Injuries and Worktime, Quarterly, January-December, 1984 (1985), pp. 7-17. MSHA utilizes information provided by coal companies on a mandatory basis as required under the Federal Mine Safety and Health Act of 1977. State average annual tonnage output per coal mining industry employee is computed using state tonnage and employee hours for all mine, plant and office workers. An 8 hour day is assumed, as is a 230 day work year (maximum number of days that can be worked under the UMWA-BCOA National Bituminous Coal Wage Agreement of 1984). Figures are slightly understated since unionized surface mine production employees work 7.25 hours per day. Since office workers at mine sites also will be affected by mine closings, their employee hours are factored into these calculations. Therefore, these figures are not be confused with more traditional miner pro- ductivity figures.

3/ U.S. Department of Labor, Bureau of Labor Statistics, Employment and Earnings, March 1986, 33, no. 3 (Washington, D.C.: Government Printing Office, 1986), pp. 86 and 97. The average weekly earnings for bituminous coal and lignite employees in December, 1985 was $644.56. The average weekly earnings for miscellaneous office personnel was $469.56. Average annual earnings for coal mining industry employees is weighted between production and office workers in each state. Annual salaries for office workers are assumed to be $24,417; salaries for coal mine workers are assumed to be $33,517.

4/ The economic losses multipliers reflect the average relationship in each coal producing state between basic and non-basic income. Mining, agriculture and manufacturing income comprise the basic sector; total community earnings less basic sector income constitute the non-basic sector. Income information and total community earnings are taken from U.S. Department of Commerce, Bureau of Economic Analysis, Local Area Personal Income, 1978-1983 Volumes 3 (Mideast), 4 (Great Lakes), 5 (Plains), 6 (Southeast) and 7 (Southwest), (Washington, D.C.: Government Printing Office, 1985) Tables 5 "Personal Income for States, Counties, and Independent Cities of the Region, 1978-1983." Multipliers were computed for the year 1983.

Higher multipliers reflect the greater percentage of support, non-basic services in the economies of these states. In those cases, basic industry supports a greater volume of services. Lower multipliers tend to reflect more industrialized dependent economies.

This analysis presumes that the non-basic sector is the service sector and is dependent on the basic sector. It should be noted that the impact on the basic sector is immediate, whereas the impact on the non-basic will occur over time.

Totals may not add due to rounding.

United Mine Workers of America

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May 8, 1986

Honorable Henry Waxman, Chairman
Subcommittee on Health & the Environment
Committee on Energy & Commerce
U.S. House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

Thank you once again for the opportunity to testify on H.R. 4567, the Acid Deposition Control Act of 1986. As I said at the hearing, the bill threatens to impose severe social and economic costs on coal miners and coal mining communities.

I wanted to respond to some of the questions that you and other members raised during the hearing. I also wanted to correct some inaccurate information that was provided the subcommittee by other witnesses.

In Representative Tauke's opening statement, he contended that the UMWA's estimate of coal market and employment disruption was based on an assumption that all emission reductions would be achieved by fuel switching. The statement is incorrect. We examined all power plants in the United States larger than 50 megawatts of capacity to determine current emissions and to estimate statewide reductions necessary by 1997. We projected compliance strategies in each state, with controls on the most likely targets first (i.e. the largest emitters with the highest emission rates). Our analysis compared the relative costs of scrubbing and switching. As we stated in our written testimony, we believe a least-cost strategy for the utilities would include a combination of scrubbing and fuel switching, but those reductions achieved by switching will result in substantial social and economic costs. We estimate that 38,000 coal industry employees would lose their jobs as a result of nearly 130 million tons of fuel switching.

You asked at the hearing whether we had reviewed a study prepared by ICF, Inc. We are aware of an ICF study done for the U.S. Environmental Protection Agency. The ICF analysis supports our conclusions. ICF projected regional coal production for the years 1995 and 2000. For northern Appalachia and the Midwest, ICF projects a minimum displacement of 106.5 million tons in the year 2000 as a result of H.R. 4567. ICF also ran a sensitivity analysis that assumed all plants would have to meet the 1.2 pound standard (as opposed to a statewide average) and projected a displacement of 127.8 million tons for those two regions. ICF advised that these figures represent a "range of impacts," so their estimates actually are very close to those of the UMWA.

The UMWA completely rejects the notion that no one is harmed if coal production is displaced. Real harm will have been done to people who have productive jobs today. Even if you choose to ignore these people, however, and look only at the "net" effect, you still will find that coal miners will suffer. Using ICF's projections, we calculated the regional employment effects of H.R. 4567. The net effect would be the loss of 9,000-14,000 coal mining jobs. This occurs primarily because of differences in mining methods and productivity.

The attached table shows net job losses based on ICF's projections. I must reiterate that the UMWA does not subscribe to the zero-sum mentality espoused by those who wish to see coal production displacement. We believe Congress must consider the plight of those who will lose the jobs they have today. Since you have been misled to believe that more jobs will be created than lost, however, I thought you should be aware of the facts.

One of the witnesses stated that the United States has 200 million tons of excess low sulfur coal production capacity. This is a gross overstatement. The entire coal industry has about that level of excess capacity, and much of it is the result of idle high-sulfur mines. He also stated that current low sulfur coal prices were $4-5 per ton in the West and $15-20 per ton in central Appalachia. I have attached a copy of actual coal prices at the mine for each state. This does not include transportation costs to the utility. As you will see, the prices quoted at the hearing do not represent real world prices.

Another witness cited the cost of scrubbers at $150 per kilowatt. What he didn't explain was that the capital cost of scrubbers is not the major factor in making the economic decision between scrubbing and switching. The cost of operation and maintenance and the relative costs of low and high sulfur coal are more important determinants in the compliance strategy decision. Unless O & M costs decline significantly or low sulfur coal prices rise more than 20 percent, there would be substantial fuel switching even if the capital costs of scrubbers is reduced.

We hope that you will recognize the economic and social harm that would occur under H.R. 4567. Your legislative record leads me to believe that you would not willingly do harm to workers, particularly when such harm is unnecessary.

I trust you will remain true to that record and avoid placing such a severe economic burden on America's coal miners.

Sincerely,

Richard L. Trumka

RLT/jlr

	Minimum Coal Production Shifts	Net Employment Shifts	Maximum Coal Production Shifts	Net Employment Shifts
	(million tons)		(million tons)	
Northern Appalachia	-35.0	-10,460	-58.4	-17,454
Central Appalachia	+35.2	+11,142	+37.0	+11,712
Southern Appalachia	+ 3.3	+ 1,113	+ 3.0	+ 1,012
Midwest	-71.5	-15,483	-69.4	-15,028
West	+69.1	+ 4,499	+90.5	+ 5,892
Total U.S.	+ 1.2	- 9,189	+ 2.6	-13,866

Source: ICF, Inc. "Preliminary Analysis of H.R. 4567", April 23, 1986. U.S. Department of Energy, Energy Information Administration, Coal Production 1984.

Note: Employment impacts are understated since DOE productivity figures exclude the hours of mine site office personnel.

Table 27. U.S. Coal Production[1], Number of Coal Mines[1] and Average Mine Price[2] by Coal-Producing State and County: 1984

(Thousand Short Tons, Dollars Per Short Ton)

Coal-Producing State and County	Number of Mines	Production	Average Mine Price
Alabama	106	27,019	$42.90
Bibb	1	38	w
Blount	4	467	37.38
Cullman	6	926	59.79
• De Kalb	2	24	w
Fayette	3	921	w
Franklin	3	269	w
Jackson	1	35	w
Jefferson	22	7,936	44.75
Marion	3	79	w
Marshall	1	50	w
Shelby	3	346	w
Tuscaloosa	21	6,750	38.92
Walker	28	8,764	42.74
Winston	8	414	37.00
Alaska	1	859	w
Yukon River	1	859	w
Arizona	2	11,522	w
Navajo	2	11,522	w
Arkansas	3	60	w
Johnson	1	15	w
Sebastian	2	44	w
Colorado	34	17,946	$23.07
Archuleta	1	277	w
Delta	3	1,620	w
Fremont	2	312	w
Gunnison	3	849	w
Jackson	2	225	w
La Plata	2	108	w
Las Animas	4	319	23.59
Mesa	1	801	w
Moffat	3	6,040	w
Pitkin	4	1,262	10.75
Rio Blanco	1	200	w
Routt	7	5,372	20.59
Weld	1	353	w
Georgia	1	125	w
Dade	1	125	w
Illinois	53	63,756	$29.89
Christian	1	815	w
Clinton	1	3,275	w
Douglas	2	1,430	w
Franklin	4	7,768	30.80
Fulton	2	1,066	w
Gallatin	4	1,432	38.61
Hamilton	1	972	w
Jackson	1	2,266	w
Jefferson	2	3,767	w
Logan	1	828	w
Macoupin	2	3,395	w
McDonough	1	487	w
Peoria	1	394	w
Perry	5	14,892	26.64
Randolph	4	4,453	27.48
Saline	10	6,598	30.64
Sangamon	1	2,195	w
St Clair	2	2,259	w
Vermilion	1	157	w
Wabash	1	1,049	w
Washington	1	1,258	w
White	1	238	w
Williamson	4	2,740	31.56

Table 27. U.S. Coal Production[1], Number of Coal Mines[1] and Average Mine Price[2] by Coal-Producing State and County: 1984 (Continued)

(Thousand Short Tons, Dollars Per Short Ton)

Coal-Producing State and County	Number of Mines	Production	Average Mine Price
Indiana	80	37,540	$24.98
Clay	4	1,758	27.09
Daviess	19	4,359	22.02
Dubois	4	742	25.01
Gibson	2	1,580	w
Greene	7	2,425	22.85
Knox	4	2,474	28.81
Martin	3	466	w
Owen	1	306	w
Pike	8	5,888	27.25
Spencer	12	1,542	21.20
Sullivan	3	2,618	w
Vermillion	1	2,322	w
Vigo	5	1,269	24.44
Warrick	7	9,787	24.98
Iowa	5	526	$25.32
Marion	2	105	w
Monroe	3	421	w
Kansas	6	1,328	$26.91
Bourbon	1	165	w
Crawford	3	695	w
Labette	1	50	w
Linn	1	418	w
Kentucky	1,215	156,774	$28.13
Bell	49	6,265	28.89
Boyd	5	331	24.33
Breathitt	29	7,549	29.87
Butler	13	1,505	29.95
Caldwell	1	59	w
Carter	5	231	19.83
Christian	1	210	w
Clay	28	2,197	30.48
Clinton	1	18	w
Crittenden	1	60	w
Daviess	7	1,395	27.70
Edmonson	1	20	w
Elliott	9	705	24.52
Floyd	106	7,721	22.71
Greenup	2	52	w
Hancock	1	94	w
Harlan	112	12,034	32.93
Henderson	1	1,083	w
Hopkins	28	11,534	24.22
Jackson	12	388	26.16
Johnson	16	988	26.43
Knott	77	6,947	29.87
Knox	48	1,338	32.48
Laurel	14	725	29.17
Lawrence	11	868	20.92
Lee	4	259	20.00
Leslie	60	6,935	29.05
Letcher	64	5,786	30.72
Magoffin	20	2,350	25.83
Martin	53	13,875	28.44
McCreary	6	887	35.67
McLean	2	209	w
Morgan	11	508	25.80
Muhlenberg	12	9,455	24.47
Ohio	16	5,741	29.03
Owsley	9	274	23.06
Perry	55	8,871	31.28
Pike	266	23,913	26.60
Pulaski	3	321	w
Rockcastle	1	232	w
Union	7	5,812	31.49
Wayne	4	474	22.67
Webster	8	4,951	29.57

Table 27. U.S. Coal Production[1], Number of Coal Mines[1] and Average Mine Price[2] by Coal-Producing State and County: 1984 (Continued)

(Thousand Short Tons, Dollars Per Short Ton)

Coal-Producing State and County	Number of Mines	Production	Average Mine Price
Kentucky (Continued)			
Whitley	27	1,788	29.94
Wolfe	9	316	18.81
Maryland	34	4,056	$28.03
Allegany	14	714	19.35
Garrett	20	3,342	29.89
Missouri	14	5,724	$24.56
Barton	1	542	w
Bates	1	684	w
Cooper	1	36	w
Henry	1	693	w
Howard	2	393	w
Monroe	1	188	w
Putnam	1	42	w
Ralls	1	148	w
Randolph	3	2,544	w
Vernon	2	452	w
Montana	9	33,000	$13.57
Big Horn	4	16,881	17.02
Musselshell	2	32	w
Richland	1	229	w
Rosebud	2	15,858	w
New Mexico	10	21,259	$19.40
Colfax	3	1,455	w
McKinley	3	6,029	w
San Juan	4	13,775	15.49
North Dakota	14	22,108	$9.46
Bowman	1	2,405	w
Burke	1	170	w
Grant	1	15	w
McLean	1	6,115	w
Mercer	4	5,696	9.26
Oliver	3	7,208	w
Stark	1	212	w
Ward	1	245	w
Williams	1	40	w
Ohio	182	39,115	$33.17
Belmont	16	6,052	32.80
Carroll	7	357	25.94
Columbiana	25	997	22.17
Coshocton	7	1,725	33.83
Gallia	3	435	w
Guernsey	6	581	35.91
Harrison	13	4,608	34.85
Hocking	6	545	15.59
Holmes	3	346	w
Jackson	10	1,023	22.09
Jefferson	15	2,106	26.20
Lawrence	3	411	w
Mahoning	3	176	w
Meigs	2	3,921	w
Monroe	2	3,479	w
Muskingum	8	2,210	30.10
Noble	5	2,911	34.80
Perry	7	2,046	25.00
Stark	10	948	18.19
Tuscarawas	22	1,795	23.65
Vinton	7	2,251	33.38
Washington	1	252	w
Wayne	1	39	w
Oklahoma	30	4,598	$32.13
Coal	1	68	w
Craig	5	1,223	33.18

Table 27. U.S. Coal Production[1], Number of Coal Mines[1] and Average Mine Price[2] by Coal-Producing State and County: 1984 (Continued)

(Thousand Short Tons, Dollars Per Short Ton)

Coal-Producing State and County	Number of Mines	Production	Average Mine Price
Oklahoma (Continued)			
Haskell	6	731	29.79
Latimer	2	363	w
Le Flore	1	306	w
McIntosh	3	284	w
Nowata	1	116	w
Pittsburg	1	56	w
Rogers	7	843	37.62
Wagoner	3	608	w
Pennsylvania	504	76,664	$33.48
Allegheny	7	1,618	38.05
Armstrong	33	4,631	30.66
Beaver	1	77	w
Bedford	3	206	w
Blair	1	176	w
Butler	20	2,511	26.96
Cambria	24	5,665	37.47
Carbon	2	102	w
Centre	11	1,810	27.21
Clarion	16	3,520	32.13
Clearfield	72	8,589	25.99
Clinton	3	244	w
Columbia	2	34	w
Dauphin	4	144	25.33
Elk	10	724	26.30
Fayette	15	1,050	26.77
Fulton	1	74	w
Greene	29	9,629	40.74
Indiana	46	12,471	35.90
Jefferson	39	3,081	32.36
Lackawanna	2	41	w
Lawrence	9	936	24.86
Luzerne	15	930	65.95
Lycoming	1	239	w
Mercer	6	752	32.72
Northumberland	9	321	41.29
Schuylkill	34	2,256	43.14
Somerset	49	6,090	23.57
Sullivan	2	60	w
Tioga	2	347	w
Venango	8	1,240	30.04
Washington	15	6,309	31.75
Westmoreland	14	809	25.49
Tennessee	90	7,211	$28.99
Anderson	12	657	32.18
Bledsoe	1	31	w
Campbell	30	1,521	27.35
Claiborne	8	1,445	40.69
Cumberland	1	24	w
Fentress	3	208	w
Grundy	1	45	w
Marion	4	519	23.76
Morgan	5	157	23.05
Rhea	2	136	w
Scott	9	713	25.61
Sequatchie	14	1,753	24.57
Texas	13	41,145	$11.14
Atascosa	1	2,810	w
Bastrop	1	12	w
Coleman	1	38	w
Freestone	1	5,879	w
Grimes	1	2,925	w
Harrison	2	651	w
Hopkins	1	2,331	w
Milam	1	5,126	w
Panola	1	11,525	w
Titus	1	9,469	w
Webb	2	378	w

Table 27. U.S. Coal Production[1], Number of Coal Mines[1] and Average Mine Price[2] by Coal-Producing State and County: 1984 (Continued)

(Thousand Short Tons, Dollars Per Short Ton)

Coal-Producing State and County	Number of Mines	Production	Average Mine Price
Utah	23	12,323	$29.20
Carbon	13	5,293	w
Emery	9	4,889	27.44
Sevier	1	2,141	w
Virginia	444	39,906	$31.17
Buchanan	197	14,749	27.33
Dickenson	75	7,066	30.48
Lee	16	2,042	34.88
Russell	14	943	w
Scott	1	12	w
Tazewell	21	2,229	25.82
Wise	120	12,859	36.06
Washington	2	3,863	w
Lewis	1	1,738	w
Thurston	1	2,125	w
West Virginia	664	130,295	$34.18
Barbour	13	2,609	34.02
Boone	65	16,731	35.65
Braxton	10	2,425	22.64
Brooke	5	1,359	36.26
Clay	6	372	33.68
Fayette	22	1,405	28.57
Gilmer	2	176	w
Grant	8	3,505	37.88
Greenbrier	13	812	42.75
Harrison	22	3,756	32.88
Kanawha	33	6,450	37.01
Lewis	8	574	26.35
Logan	91	10,525	33.64
Marion	11	7,863	37.42
Marshall	3	5,240	w
Mason	1	105	w
McDowell	61	7,507	35.07
Mercer	3	210	w
Mineral	6	613	26.94
Mingo	34	7,561	37.04
Monongalia	32	17,555	31.66
Nicholas	46	5,809	35.18
Ohio	1	152	w
Preston	40	3,143	21.64
Raleigh	36	8,463	37.79
Randolph	14	1,531	29.03
Tucker	2	274	w
Upshur	10	3,139	30.60
Wayne	1	106	w
Webster	11	1,824	28.16
Wyoming	52	8,481	36.68
Wyoming	27	130,914	$11.89
Campbell	14	106,811	9.15
Carbon	5	5,221	30.64
Converse	1	3,339	w
Hot Springs	1	43	w
Lincoln	2	4,068	w
Sheridan	1	2,531	w
Sweetwater	3	8,902	w
U.S. Total	3,566	890,644	$25.61

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[1] Excludes silt, culm, refuse bank, slurry dam, and dredge production except for Pennsylvania anthracite. Excludes mines producing less than 10,000 short tons of coal during the year.

[2] Average Mine Price is calculated by dividing the total f.o.b. mine value of the coal produced by the total production.

w Withheld to avoid disclosure of individual company data.

Note: Total may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-7A, "Coal Production Report."

The CHAIRMAN. Thank you very much, Senator Byrd.
Senator Rockefeller.

STATEMENT OF HON. JOHN D. ROCKEFELLER IV, A U.S. SENATOR FROM THE STATE OF WEST VIRGINIA

Senator ROCKEFELLER. Mr. Chairman, I certainly want to compliment the senior Senator from the State of West Virginia. He and I have worked together over the years on many matters with respect to coal, but there is no matter where the minority leader has been more persistent and aggressive than with respect to the sensible resolution of the problem of acid rain. And I think the senior Senator from West Virginia recognizes, as I do, that acid rain is a problem. We do not deny that.

When I was Governor, the folks from my Department of Natural Resources were able to measure the pH contents in the streams of West Virginia, and other Governors were able to measure it in other States throughout our part of the country. But the point is that as the senior Senator makes very clear, it is not just a matter of sulfur that creates acid rain. There are nitrogen oxides, there is ozone which might implicate other types of industries, there are mobile sources, automobiles, and there are other aspects as well as aspects which come from utility use.

People are very quick, as the senior Senator from West Virginia knows, to criticize coal. Coal is an easy whipping boy. It is an unknown to most people; 99.9 percent of Americans have never been in a coal mine, have no idea what a coal mine is like. They have an ancient view of coal mining. Their ignorance is extensive with respect to coal mining.

Senator Byrd and I know very well that coal is what this country has. When oil is transported from other countries to ours and approximately 1 percent of all of the oil that is transported is spilled, that is another kind of environmental damage. But spills draw momentary notice, beaches are crushed, birds are killed, bathers are inconvenienced, television has an interesting several days, and then it is forgotten. But oil brings with it problems.

Oil is a declining resource in this country as well as abroad. People are interested in nuclear power. It has always been a matter of interest to me, as well as I know to the senior Senator from West Virginia, that nuclear power is the one industry which our Government subsidizes and yet it is also the one fuel source which the free market rejects. I have always found that interesting.

I need not go into the Russian disaster and I need not extend that image to unnecessarily cause concerns. But coal is constant. Coal can be mined safely and is much more done so. Probably the greatest industrial revolution in the last 10 years has been the efficiency and productivity and harmony with which coal is now mined. The relationship between labor and management, the increase in productivity per miner tons per man per day, per woman per day—coal is abundant, everlasting in terms of our needs in our generation and future generations to come.

So, as Senator Byrd has pointed out, let us get at it. Let us get at the way to mine it and burn it cleanly. We can mine it and mine it relatively safely and ever more safely. So let us get at the question of burning it cleanly. Why can we not take the Senator's program—the clean coal technology program—why can we not take that and make the national commitment to that that we do to so many other things?

Why was it that Senator Byrd had to fight so hard in so many ways and with the cooperation of this committee and Senator McClure, Chairman McClure, why was it that you had to fight so hard to get that money into the budget for this most abundant of all resources when there is a clear way—there are clear series and sequences of break-throughs that are available with money and with brain power to burn coal cleanly?

Now people will say well, sure, you are from West Virginia. That is the kind of thing you are going to say, Senator Rockefeller or Senator Byrd, but when Senator Byrd talks about unemployment, he knows what he is talking about. When we talk about unemployment in West Virginia, I know what I am talking about. In 1982 and part of 1983 we had 21 percent of our people unemployed. Senator Byrd and I go into the southern coal fields of West Virginia, and you go to some of the counties and there may be 80 percent of the people in a given community who are unemployed, and you and I can name a number of them. When we go into the northern parts, it is the same.

Now the coal is there. You do not have to bring it from across the seas. Our people know how to mine it. We do it now with environmental dignity, environmental success. The question is burning it. We can burn the low-sulfur coal. Senator Byrd wants us, as do I, to be able to burn the high-sulfur coal through the intelligent application of technology and American brain power. Yet you had to fight with everything that you have to get the $400 million into the budget.

I am not sure what kind of resistance yet, Senator Byrd, that we face with respect to the administration, in terms of implementing ways of deploying those programs once the successful ones are picked and they become successful.

Mr. Chairman, it seems to me that what Senator Byrd has said and what he is fighting for and what he has fought for is imminently sensible for the security of this Nation. We know what acid rain is. We know that acid rain can be diminished. We know that in a period of time acid rain can be, in fact, eliminated if a number of things are done. Only one of those things is on the utility front—the coal-burning electric power generation front.

Senator Byrd has authored and I have cosponsored legislation which aims at that which tries to take advantage of what the President and the Prime Minister of Canada have put into words but have not yet put into effect. You have made the money available, you have fought for it in the Appropriations Committee, and you have delivered it, and now the administration, with our prodding and our urging, has to make this come true.

And why is it sensible? Because coal is cheaper, because coal is available, because coal is there for our national security, because coal is American, and because there is vast unemployment in the eastern section of our country, particularly Appalachia, where coal is.

We do many things for farmers in this country and every time another farmer closes down that we read about it, the newspapers cover it and the television folks go out and interview the people, and we are moved. But when another 200, 300, 400 coalminers are thrown out of work, this Nation seems to say, well, I guess that is just part of the way things have been; that is part of destiny. Well, it is not, and it need not be.

Senator Byrd has been the leader in this fight for clean coal, which means jobs in Appalachia, which means cheaper energy for Americans and a cleaner environment. Mr. Chairman, I want to compliment the Senator, not only for his testimony this morning, but for the fight that he has carried on, not only this year but in previous years. He is an effective leader for clean coal, he is an effective leader for coal, and he is an effective leader thereby for a cleaner environment. I congratulate him.

And I compliment you, Senator Byrd, and I am grateful for your presence here.

Senator BYRD. Mr. Chairman, I thank the Senator from West Virginia.

Governor Rockefeller speaks based on his knowledge of serving as the chief executive in West Virginia for two terms, based on his experience as Secretary of State in West Virginia, based on his having served in the State legislature. I do not know of anyone who would be in a better position to know what the impact economically, psychologically, and socially would be if the acid rain legislation that is making its way through the committee in the House were to become law more so than would Senator Rockefeller.

Mr. Chairman, I have been in politics 40 years in West Virginia. I grew up in a coal mining community. My father worked in the coal mines, and I married a coalminer's daughter. I know something about the problems of coalminers. I also know that coal, as Senator Rockefeller has stated, is an almost limitless resource. It is here, it can be mined, it can be burned; it can be burned in ways that are clean and environmentally accepted, and it does not present the problems that nuclear power presents.

The able Senator from West Virginia who sits on this committee has, with good reason, indicated that he would not want at this point to expand on the problems that we see as a result of the Chernobyl accident, but he certainly is correct in making reference to that accident.

We have plants in this country, nuclear plants. Some of them have cost billions of dollars—billions. There are some right now that have cost billions of dollars and that have proved to be costly by factors of several times over what the original estimates were. Some of them may never be used if the people who are in the vicinities thereof have their way.

Chernobyl has scared people. It has scared me. And its impact on the welfare, the health, the well-being of the people in the Soviet Union cannot be hidden forever, as they cannot be hidden from the people in the Eastern-backed countries that are associated with the Soviet Union.

The Western countries are very knowledgeable as to what the long-run ramifications are going to be as much so as we can determine at this time. I guess nobody really knows what the final results will be. But I am saying to this committee we are talking about a penny compared with the billions of dollars that are being spent on nuclear powerplants in this country. We are talking about $400 million.

And I had to go to the mat in that conference with the House of Representatives more so than I have ever had to go to the mat in any conference with the House in all of the years that I have been on that Appropriations Committee, and that is 28 years, for 400 pitiful little—$400 million. We are talking about spending billions of dollars on nuclear plants.

The administration wanted $100 million. Finally, with the chairman's stalwart support here, we were able to agree on $400 million over the next 3 years. And I note that there are some indications that the administration may be reluctant to come up with the additional $350 million.

I am happy to see that the Reagan administration, according to Randall Davis, OMB's Associate Director for Natural Resources Energy and Science, the Reagan administration will not support a higher—and I am not happy about that, but I will read it—the Reagan administration will not support a higher authorization for the clean coal technology program beyond the current level.

And here is what I am happy about. President Reagan will veto the acid rain bill now moving through Congress if it reaches his desk in its present form according to an Office of Management and Budget official. The $400 million appropriated for the clean coal program is sufficient at least for now, Randall Davis told last week's gathering of the National Coal Council in Washington. Davis shut the door on those hoping to persuade the administration to free up the additional funds left over from the demise of the Synthetic Fuels Corporation.

That is a report that appears in publication, Inside Energy with Federal Lands, June 9, 1986. What I am saying is we are being penny-wise and we are being pound-foolish. We are having myopic vision, and it is plain stupid that we argue and fight and wrestle around over $400 million. And we have no hesitancy in recommending millions, yes billions, for expenditures overseas.

We are taking about a resource here that is plentiful, it can be burned cleanly, and that can stand this Nation in good stead in the event of a national emergency. Suppose there is a national emergency that hits this country. We have wasted a lot of time already. This resource, if we had had the gumption and the foresight and the common sense to move ahead with research and demonstration projects, I have no doubt that this Nation would be prepared in the event the gas lines come back, and they may one day, we would be prepared in the case of a national emergency to be fully energy self-supporting. It could be done with coal.

But coal has had its ups and downs, mostly downs, and it has been the stepchild in the energy family. So it just does not make sense for us to continue to have this glaucoma that is blind to the peripheral dangers that we are courting with a possible nuclear disaster.

So I thank the Senator for what he has said. I am glad he is on this committee. It is a good committee, and I feel that this committee has seen the light over the years and will help to provide the leadership that is needed as we move forward in this new and promising horizon of clean coal technology.

I thank you.

The CHAIRMAN. Thank you, Senator Byrd.

Senator Melcher.

STATEMENT OF HON. JOHN MELCHER, A U.S. SENATOR FROM THE STATE OF MONTANA

Senator MELCHER. Thank you, Mr. Chairman. I want to pick up on one thing my good friend from West Virginia said earlier. He said when you say West Virginia, you think of coal. Well, when you think of Montana, what do you think of? Maybe you think of cowboys and Indians.

Senator BYRD. Senator Melcher. I think of Senator Melcher. [Laughter.]

Senator MELCHER. That is pretty good. You might think of cowboys and Indians and cattle rustlers and maybe even copper, but without starting an argument I wonder if I could just very humbly say that Montana has coal underlying those rolling plains. The 106 to 115 billion tons of recoverable coal is by far the most held by any State, and indeed a greater amount of reserve than almost all but three or four countries in the world have.

Over the years, we have been developing this coal rather slowly. Colstrip units 1, 2, 3, and 4, a complex of generating plants, is in my home county in Montana. During the 10 years it took to construct this complex, the situation about air quality arose.

The scrubbers that were allowed on Colstrip units 1 and 2, I am proud to say, due to legislation passed here in Congress, were improved. Those scrubbers for Colstrip units 3 and 4, the last two of the complex, were further improved over the original ones on Colstrip units 1 and 2.

We have low-sulfur coal. So the sulfur emissions are not as large a concern to us as fly ash and nitrous oxide. But, nevertheless, built into those plants were scrubbers of the best technology available. This is a term in the statute which is what we should have in our plants. The scrubbers in Colstrip generating plants represent the best technology available, and so we have emissions from those plants very much below the standards. The cost of generating electricity from those plants is roughly 43 to 44 mils per kilowatt.

About 9 years ago, I was asked, having just become a member of this committee, to address a very auspicious meeting of nuclear engineers, here in town. An honorarium was involved, I think it was $500. My statement was the best $500 they ever invested.

I told them that the question of the economics of generating electricity had already passed between nuclear and coal. I am talking about the clean burning of coal without any air pollution. I told them that the best information I could get from the General Accounting Office as of that moment was that a nuclear plant, already under construction but only about half built, would be generating electricity at around 60 mils per kilowatt, well above the cost of coal-generated electricity at the new plants at Colstrip units 1 and 2.

I told them that the cost of nuclear generated electricity did not include the expense involved in storing the spent fuel rods and that neither I nor the General Accounting Office was capable of determining what that cost would finally be. In addition, there is the cost of dismantling the plant eventually, and nobody has yet, as far as I am aware, come up with that cost.

So, Senator Rockefeller, I am going to pick up on Chernobyl. That accident at Chernobyl could be avoided here. We are instructed that it can be avoided here. We are advised that it can be avoided here and that it will not happen here—but it could in times of carelessness or human error. We could find errors like that occurring here, even with the better plants.

I find it odd that in the struggle we have to bring coal-fired boilers in the plants involved into better compliance with clean air technology and to continually upgrade clean air technology, we find it so difficult to find the money to pursue it.

Now, Senator Byrd, your comments as far as I am concerned are right on target. You are putting the case before the public. The $400 million, is a small amount compared to the billions that have been spent and will be spent out of the Treasury on nuclear energy. This never adds up. In the research and development and other measures we are taking cooperatively with the people that have the coal-fired plants, why is there not a true partnership between government and the private sector to get the answers?

I think it is great, Senator, that you as our leader, our Democratic leader, have found the time for all the rest of us in the coal caucus to carry the load of leadership for coal, besides all your other leadership duties. I am pleased that on this committee there are a number of Senators who are part and parcel of the coal caucus who are continuing to battle for our common goal of making coal, which we have in abundance, the premier source of electrical energy and for that matter the premier source of energy for the other means throughout the country.

And I thank you very much for that. I commend you for your comments.

Senator BYRD. Mr. Chairman, I thank the distinguished Senator for his support and his leadership in this area and for his supportive statement.

The CHAIRMAN. This is not the time or place to get into a debate over nuclear power. I do not find it necessary to be antinuclear in order to be procoal. I am for a balanced energy resource policy for this country. That does require both coal and nuclear in our future, and I hope that is where we will end up. As a matter of fact, references to Chernobyl—any dispassionate reading of the record would, I think, lead to the conclusion that that simply cannot happen in our plants and will not happen in our plants. Those who play upon fears do a disservice to the American public and perhaps the cause which they seek to serve.

I have another meeting I must attend for a few minutes, so I will turn the gavel over to the distinguished Senator from Virginia, Senator Warner, who will preside in my absence.

Senator BYRD. Mr. Chairman, before you leave, may I just impose on you for 30 seconds? I do not mean to say that I am against nuclear power.

The **Chairman**. I did not understand you to say that.

Senator **Byrd**. I did not mean to imply that.

The **Chairman**. I listened very carefully.

Senator **Byrd**. I think we are being penny wise and pound foolish. It is a mystery to me as to why our Government continues to support research in nuclear power, far more so than it does with respect to coal research. I am simply saying that here is a product that is safe; it can be burned cleanly and in an environmentally acceptable manner.

Nuclear? Fine. I am not trying to scare the American people. I do not mind saying I am scared by Chernobyl. Nor am I saying that we in this country cannot be far more protective and farsighted and wiser in the handling of these nuclear powerplants than was the case at Chernobyl.

The **Chairman**. Senator Byrd, I understand your statement, but I am constrained to say that the fear that we do not understand is greater than the danger we do understand. There have been far, far more people who have lost their lives in coal mining than have ever lost their lives in nuclear, and yet that is a risk you accept because it is a familiar risk. It is one that you have grown up with and you understand it, and the communities in which you live understand that risk and accept that risk in an offset for the economic and social benefits that come from coal mining. I understand that.

Senator **Rockefeller**. Mr. Chairman, could I interject a comment?

The **Chairman**. Of course.

Senator **Byrd**. I have one, too, I want to interject. [Laughter.]

Senator **Rockefeller**. I have heard that argument and I do understand that argument and it is technically and mathematically correct. But I think it should be pointed out that the history of the last decade or so, since 1969, in coal mining has been the history of the precipitous decline on not only fatalities in the mines but also injuries in the mines and workdays lost in the mines.

The **Chairman**. We put a lot of money into research and development of safety, certainly not the same billions of dollars we put into nuclear research, but I have supported that and I believe it is necessary.

Senator **Rockefeller**. I think it is important to say that the efforts and the results on safety in the coal mines has been an extraordinary American success story, although it is not where it should be yet. And I think what occurs to some of us is that you are right about nuclear power. And this is not the day to debate nuclear power. We are going to have our hearings on Chernobyl and those days will come.

But I will say this: When Three Mile Island took place in this country, I was Governor of West Virginia, and the particular location of that plant is such that had their been emissions and had the winds been blowing in the easterly manner in which they ordinarily do, the eastern part of West Virginia would have been affected. And I want to tell you that as Governor I wasted no time whatsoever in sending air-monitoring equipment, helicopters, and everything else I could think of up to that part of the country to measure.

Now as it turned out, there was no problem.

The CHAIRMAN. You wasted your money, did you not?

Senator ROCKEFELLER. But if and when the day comes that there is, either in this country or any other country, the Soviet Union included, a disaster, let there never be a comparison between the magnitude of that disaster with respect to nuclear power and the magnitude of the improvement of the record of safety for coal miners as exercised over the last 15 years.

The CHAIRMAN. There is no question that safety in coal mining has improved. There is also no question that the risk of life of the actual accidents and fatalities in coal mining are greater than in nuclear, even yet. So there is more to be done in coal mining health and safety, and we will continue to make those efforts.

My only point is to indicate to try to keep the rhetoric in balance if we can, as we try to keep energy policy in balance. There were far more people killed and injured at Bophal than were, so far, at Chernobyl. And you have a plant in West Virginia utilizing the same technology.

Now I am not going to suggest that that plant in West Virginia is operated with the same laxness that was characteristic of the operation of a plant in India which the Indian Government insisted on better than half the ownership and most of the onsite management. I make that statement because I do not want to assume that I am simply blaming Union Carbide for what happened in Bophal; I think there were a lot of other reasons why it happened, indigenous to local politics. Nor do I want this discussion to get too far off into the comparison of hazards between two different energy sources. But I do believe that we have to be careful as we go through this not to exploit the fears of one in order to enhance the economic value of another.

Senator WARNER. Mr. Chairman—

Senator BYRD. Mr. Chairman, if I may just react to that. I do not want to impose on the chairman further, but I hope the chairman will not misunderstand the Senator from West Virginia, Mr. Rockefeller, and this Senator, in attempting to exploit anything that has to do with Chernobyl. Far be it. And the chairman's reference to rhetoric, I hope that I do not infer from that that we have engaged in just rhetoric this morning. When the chairman talks about casualties and deaths and accidents in coal mining, that gets pretty close to home.

My own brother-in-law died of silicosis pneumoconiosis and black lung and cancer of the lung and his father was killed in a slate fall in the coal mines. So when we talk about mine safety, I can remember when my dad's mining experience went back to the days of the carbide lamp and the cloth cap.

We have come a long way since those days, but we have not come far enough. And one of the reasons we did not come far enough fast enough is the same problem that we are running into in this clean coal technology is the penny-wise and pound-foolish philosophy followed by the Federal Government

The chairman has been supportive of improved safety mining techniques, legislation promoting such, appropriations promoting such, and I thank him for that. We do not have a great deal to brag about up until recently, and we still have a way to go with reference to safety in the coal mines. Fortunately, we have come a long way, and I thank the chairman for his support.

I also thank him again for his support of appropriations for clean coal technology and I hope that he will use his talents—and they are very considerable—and efforts with me and others in trying to get the Administration to forge ahead and request the remainder of the $750 million—I believe it is $350 million—as soon as possible so that we can get into the retrofitting of these technologies, rather than just focusing on construction of new plants which the chairman himself mentioned in his statement.

I thank the chairman, and if I have been instrumental in delaying his departure, I am sorry.

The CHAIRMAN. Senator, I have been supportive, and I expect to continue to be supportive of both programs.

And I turn the gavel over to Senator Warner.

Senator WARNER [presiding]. Before the distinguished Senator leaves, I want to add my praise. I have worked with him on this problem for many years and the people of Appalachia are deeply grateful, Senator.

Senator BYRD. I thank the Senator from Virginia for his support and his very supportive statement and I thank him for the opportunity to appear before his committee over which he presides with a dignity and charm and a sense of fairness as rare as a day in June.

Senator WARNER. Thank you, thank you, thank you. I am speechless. I thank the Senator, very much.

Senator BYRD. I thank the chairman. I thank Senator Melcher and I thank Senator Rockefeller.

If there are no further questions——

Senator WARNER. I do not believe there will be further questions.

Senator BYRD. I thank the chairman.

Senator WARNER. We will now have Panel I from the administration: The Honorable Lee Thomas, Administrator, Environmental Protection Agency; the Honorable Mary L. Walker, Assistant Secretary for Environment, Safety and Health, Department of Energy; Mr. Donald L. Bauer, Acting Assistant Secretary for Fossil Energy, Department of Energy.

Senator WARNER. Mr. Thomas, if you will kindly lead off, we will proceed with the direct testimony of all the witnesses and then proceed to questions of the panel.

STATEMENT OF HON. LEE M. THOMAS, ADMINISTRATOR, ENVIRONMENTAL PROTECTION AGENCY

Mr. THOMAS. Thank you, Senator.

We appreciate the opportunity to be with you today to discuss this important topic. I think you have a full copy of my testimony. If that would be entered into the record, I think I will just highlight the major points of that testimony before turning to my colleagues for their statements.

EPA's review of clean coal technology and therefore my testimony and my discussion today really are in the context of implementation of the Clean Air Act, issues associated with acid rain, and the report of the special envoys, Drew Lewis and Mr. Davis.

First, turning to clean coal technology and its emphasis as far as EPA is concerned, we have really looked at the issue closely, particularly over the last several years, as it relates to retrofit technology. When we look at 65 percent of the SO_2 emissions in the United States from coal-fired powerplants, 30 to 35 percent of the NO_x emissions from powerplants, the issue of life extensions which has already been noted by earlier commentors, the fact that it appears that existing plants are being extended as far as life is concerned significantly, then retrofit technology as it relates to clean coal is a dominant issue from our point of view.

Second, when we look at technology, we look not at whether we can control the release of pollutants, in this regard SO_2, NO_x, and particulate matter, but particularly SO_2 and NO_x, but rather how do we reduce the cost of those emissions.

And finally as we look at the special envoys' report, we see clearly the emphasis on utilization of clean coal technology in the area of retrofit applications as a major part of the strategy for dealing with acid rain. If you look at their criteria, for instance when they talk about the $5 billion program, you see first focusing on largest potential for SO_2 and NO_x reductions; second, focus on looking at the lowest cost per ton of these pollutants removed; third, looking at retrofit technology, particularly those plants that may have some transboundary effect; and a focus on finally applications for high-sulfur coal facilities.

So in that report which was a report on acid rain, as you know, was a highlight on clean coal technology, but a highlight on focusing on those criteria to relate that technology to an acid rain program. Therefore, the types of technologies that we focus on are more limited than the broad clean coal technology effort that has been pursued over the last number of years.

For instance, in the precombustion, combustion, and postcombustion stages, the three stages we would look at, in precombustion we think there is still a good bit to be gained by looking at coal cleaning, advanced coal cleaning, various coal cleaning technologies particularly when used in application with other technology.

In the combustion stage, the LIMB technology [limestone injection multistage burning technology] that we have pursued in EPA progressively we think has a lot of potential, particularly for retrofit, and we are going to a commercial demonstration of a wall-fired project with LIMB this year in conjunction with the State of Ohio and Ohio utilities at a 105-megawatt plant that we think in 1987 will show commercial viability of LIMB technology with a humidifier addition which could result in as much as a 70-percent reduction in SO_2 and 50- to 60-percent reduction in NO_x.

We also feel that low-NO_x burners and reburning technology for NO_x are both technologies that are available and in fact are available commercially and should be focused on as far as retrofit is concerned.

Fluidized bed is clearly a major technology, but a technology that appears to have more application to new sources than existing sources.

When we look at postcombustion, improved scrubbing, wet scrubbing appears to be a very viable technology, and low cost or dry scrubbing particularly with low- or minimum-grade sulfur coal also appears to be technology that would be very good in the near term.

So if we look at that range of technology and several others, we see the possibility in the next 5 years, definitely the next 10 years, of commercial availability of alternatives to the current process for burning coal that would have environmental advantages.

If you turn from this and look at where we are with acid rain in the acid rain policy issue, it has major implications. As you know, the administration's policy on acid rain is that acid rain is a major environmental problem in this country and in Canada. However, we do not believe that the current state of knowledge can sustain any judgment with respect to the level of emission reductions needed to prevent or eliminate damage from acid rain.

We are pursuing a policy that includes implementation of the Clean Air Act. Look at the kind of regulations that have gone into place during the last several years, even the last 1½ years since I have been Administrator, that impact on nitrogen oxide reductions, particularly from mobile sources or $S0_x$ reductions, particularly from stationary sources.

We are also pursuing an aggressive research program, a program that is costing over $85 million a year, which includes aggressive work on water acidification, forest impact, atmospheric processes, and materials damage that in my opinion over the next 2 to 3 years will result in a significant decrease in the uncertainties associated with the acid rain question.

Also, looking at a series of strategies with over 30 States for implementation of additional controls on SO_2 and NO_x, if we determine they are necessary, and finally a pursuit of all regulatory initiatives under our existing authority to determine what additional controls may be necessary if in fact we feel they are necessary.

And finally a review of technology development with the Department of Energy in the lead on the kind of clean coal technology that you are talking about today. Those are on parallel tracks. It is not a sequential process, development of one and then the implementation of another, it is a parallel review. If out of our research program we determine that additional controls are necessary for SO_2 or NO_x to overcome problems with acid rain, then additional controls will be required, whether or not new technology is available.

So in conclusion, Mr. Chairman, I would say clearly that timing of technology development is critical if it is going to have relevance to the possible additional reductions that may be necessary of SO_2 and NO_x. I would say the kind of timeframe that is talked about in legislation, such as 4567 or legislation pending on the Senate side, is 5 to 10 years where significant reductions would be required.

The kind of timeframe where I think we will arrive at answers in our research programs to determine whether additional reductions are necessary is probably 2 to 3 years if they are required in the same kind of timeframe that you are looking at under that legislation, which would be 3 to 7 years beyond that; so 5 to 10 years.

So if reductions are required, I think the next 5 to 10 years are going to be critical. I think therefore from an environmental view the kind of reductions that may be required in SO_2 and NO_x—by that I mean the kind of development that is done during the next 5 years—is going to be critical to determine whether it has application or not to existing plants as well as new plants, with existing plants taking priority from an environmental view as far as SO_2 and NO_x is concerned.

We appreciate the opportunity to be with you today.

[The prepared statement of Mr. Thomas follows:]

TESTIMONY OF
LEE M. THOMAS
ADMINISTRATOR
U.S. ENVIRONMENTAL PROTECTION AGENCY
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
U.S. SENATE

JUNE 9, 1986

Mr. Chairman and Members of the Committee, I am pleased to be here this morning to discuss EPA's views on a matter of mutual interest, clean coal technology.

The term clean coal technology encompasses a large group of emerging technologies which allow the burning of coal with significantly reduced emissions of the major pollutants SO_2, NO_x and particulates. These technologies are in various stages of development and use. While these technologies share a common goal - the use of coal in a way which is environmentally sound - each has its own specific use potential, and economic and environmental benefits. Because of the concern over SO_2 and NO_x as they relate to the acid rain debate, and because a high percentage of these pollutants is emitted from existing coal-fired boilers, EPA has tended to focus its attention and resources on a group of emerging technologies which show the greatest potential for use in retrofit situations. It is these technologies that I will address in my testimony this morning.

Applications of Clean Coal Technology

There is a wide range of clean coal technologies which appear promising for use in retrofit situations. Such technologies as applied to coal-fired power plants can be associated with three fundamentally different applications. The first involves the retrofitting of new control technology to existing coal combustors with the aim of further lowering emissions of the aforementioned air pollutants. In the second application, emerging clean coal technologies could be embodied in the design of a new power plant or industrial facility. The third major application involves the retrofit of existing oil or gas-fired power plants to allow the substitution of generally less expensive, but potentially more environmentally damaging coal.

Several of the existing and emerging clean coal technologies can be applied to two or three of these major applications. For example, flue gas desulfurization (scrubbers) can be utilized for existing coal power plants, or be applied to new coal-fired power plants. Other technologies, however, may be appropriate for only a single application class. For example, Limestone Injection Multi-stage Burner (LIMB) technology currently under development by the EPA seems particularly attractive to retrofitting of existing coal-fired power plants. This is the case since, if successful, such a technology should be quite low in capital costs, require little room for retrofit and achieve moderate sulfur oxide and nitrogen oxide emission control from existing sources. Another example would be low-

BTU, combined cycle-gasification which, in light of its relatively high cost on a retrofit basis and its relatively high overall conversion efficiency, might be particularly applicable to new coal-fired power plants. One more example would be chemical coal cleaning. Although relatively expensive, this process may yield sufficient sulfur and ash removal to produce an affordable fuel which could be used in existing oil and natural gas boilers without unacceptable environmental degradation.

It is very difficult, however, to make definitive statements about the general usefulness of a given technology. This is because several factors can affect the choice of technology at any given source. These factors include plant size, remaining plant life, type and price of available controls, fuel source used, location or space requirements of added equipment and applicable limitations on emissions. This list points out the fact that decisions on the usefulness of different technologies are very site specific.

In our view, the most important application category for the focus of clean coal technology development would be the coal-fired retrofit application. Approximately 65% of the SO_2 emissions in the U.S. currently come from coal-fired power plants. This figure gains additional significance because of a recent industry-wide practice of rehabilitating these existing plants; a practice commonly referred to as life extension. Life extension results in extending the economically useful life of many of these plants by two or more decades beyond what was earlier anticipated. This postpones the rate at which new sources will replace existing sources, making New Source Performance Standards a less effective way of reducing overall emissions in the near or middle term. Thus, we believe that the potential need to control sulfur oxides and nitrogen oxides from existing sources makes retrofits the most important application category.

Potential Benefits of Clean Coal Technologies

The application of clean coal technologies, particularly in existing power plants, could provide significant environmental benefits. The Agency is currently participating in a major research program to determine the role of SO_x and NO_x in acid deposition and other related environmental problems. If it is determined that additional reductions in SO_x and NO_x could alleviate these problems, the existence of inexpensive and efficient retrofit technology would be essential to formulating an acid rain control plan that would have broader public appeal.

With currently available technology, it is possible to control emissions from coal-fired power plants on a retrofit basis for most facilities. Therefore, the major question we may face is not, can we control the release of these pollutants, but, how can we reduce the cost of controlling SO_2, NO_x, and particulate matter emitted by existing coal-burning facilities. In this regard the major challenge is to reduce the cost of controlling emissions, especially of sulfur oxides since this is often the most expensive pollutant to control. Current technology, specifically flue gas desulfurization (scrubbers), costs on the order of $350 to $800 per ton of sulfur removed from the stack of a plant burning high sulfur coal. This and other clean coal technologies must compete with potential for fuel switching as a cost efficient control option.

One of the major goals of the clean coal technology program is to aid in the development of technologies that will achieve pollution control from coal combustors both at a high control efficiency and at a lower cost than conventional technologies. Such savings would offer electricity rate payers the possible benefit of substantially lower incremental costs associated with any need for a large scale retrofit program. For example, we have estimated that if our LIMB research, development and demonstration program is successful in meeting its technical goals, LIMB technology can in many cases substitute for scrubbers in a national retrofit program with the result that electrical rate payers could save on the order of $.2 to $.7 billion annually over a full scrubbing scenario, depending upon the magnitude of the program and the ultimate cost-effectiveness of the emerging LIMB technology.

Joint Report of the Special Envoys on Acid Rain

Indeed, the Special Envoys Report, which has been fully endorsed by President Reagan, also recognized the need to "develop retrofit technologies applicable to the largest number of existing sources." The Joint Report of the Special Envoys on Acid Rain made recommendations in three areas: initiation of a five-year, $5 billion control technology demonstration program; emphasis on research to help answer critical scientific questions related to transboundary acid rain; and cooperative activities such as bilateral consultations and information exchange.

With regard to the initiation of the technology demonstration project, we believe that the Joint Envoys provided a great deal of important guidance in their statement of criteria for selection of projects. The report identifies the key elements which should be incorporated into an effective joint industry/government effort to promote innovative technology for acid rain control. It states the preference for demonstration projects oriented principally toward rapidly augmenting the menu of available options for retrofit control of existing sources of SO_2 and NO_x. The report then provides additional specific criteria for selection of projects for funding.

The first criterion is that preference should be given to "projects that have the potential for the largest emission reductions, measured as a percentage of SO_2 and NO_x removed."

The second specific criterion is that among those projects with similar potential, preference should be given "to those that reduce emissions at the cheapest cost per ton." To be responsive to the need for a menu of low cost technologies, EPA believes it is important that projects have cost-effectiveness goals substantially below the dominant current technology, lime-limestone flue gas desulfurization (FGD), also referred to as "wet scrubbing."

The third criterion is that of wide applicability. "More consideration should be given to projects that demonstrate retrofit technologies applicable to the largest number of existing sources, especially existing sources that, because of their size and location, contribute to transboundary air pollution." Given that several technologies meet the performance and cost criteria, the selections should emphasize those technologies which could be applied to the largest number of existing sources. Further, the report recommends that to the extent it is possible, projects selected "should also result in some near-term reductions in U.S. air emissions that affect Canadian ecosystems."

The final criterion stated that "special consideration should be given to technologies that can be applied to facilities currently dependent on the use of high-sulfur coal." This requires a careful analysis of the characteristics of existing plants and their current sources of coal. Analysis would then be conducted to select those technologies which matched well with the facilities accounting for a significant percentage of current high sulfur coal use. High sulfur is usually interpreted to mean coal with a sulfur content above 2.5 percent.

The Envoys' Report recognized that the high cost of currently available control options is "a significant impediment to the development of a U.S. consensus on acid rain." It is clear that the Joint Envoys and their staffs gave a great deal of thought to the specific design and selection criteria which would provide the greatest probability of success in commercial demonstration of innovative technologies which could assist in achieving consensus on control of acid rain. Conscientious application of these criteria in carrying out such a program requires a great deal of effort in assembling the necessary data bases and procedures to analyze potential innovative technologies, and to ensure that the most promising, environmentally beneficial technologies are proposed and selected for implementation. It is clear that this front-end effort would be justified by an increase in the probability of success of the program.

Specific Clean Coal Technologies

Before discussing some specific clean coal technologies, I would like to provide two caveats: First, since the technologies that I will be discussing are emerging technologies, most have not been tested on a scale which would allow for assured prediction of results. Bringing a technology to the commercial demonstration stage often involves an unpredictable number of years of research, development and pilot testing. Therefore, it should be understood at the outset that predicted efficiencies and estimated dates of availabality are somewhat speculative. Secondly, the list of retrofit technologies which I will discuss is not an exhaustive list of the full range of technologies presently being examined.

Control technologies can be classified by the point within the overall process where the emission control occurs. The normal categories are: 1) pre-combustion; 2) combustion; and 3) post-combustion. I will now discuss these categories and specific emerging retrofit technologies within each of these categories.

Pre-combustion

As the name implies these technologies remove the source of the pollutant from the coal prior to combustion in the power plant. Physical and chemical coal cleaning are the technologies of this type which remove moderate amounts of sulfur and ash. Technologies which produce gaseous or liquid synthetic fuels are not considered here. Physical coal cleaning is most likely to make a significant contribution in the near term.

Physical Coal Cleaning - Currently, physical coal cleaning (PCC) is applied primarily for removing ash and enhancing Btu value; sulfur removal is only a secondary objective. The more advanced commercial PCC facilities may remove significant amounts of sulfur (20-30%). Nevertheless, for high sulfur coals, PCC, in combination with other technologies, can be a very cost-effective approach for SO_2 emission reduction. PCC, through its ash removal capability, can offset the increase in particulate loading to existing fly ash collection equipment caused by injection of alkaline materials in LIMB, spray drying, and other SO_2 emission reduction techniques.

Combustion

Emissions of both SO_x and NO_x can be controlled in the combustion zone. Some technologies can be applied directly to existing boilers while others require significant modification and/or replacement of the combustion system. Three of the more promising technologies are discussed below:

Limestone Injection with Multi-stage Burners (LIMB). EPA has been very active in the development of LIMB. This technology uses low NO_x burners and sorbent injection to achieve a 50 to 60% reduction of both SO_x and NO_x. If integrated with a humidification and sorbent recycle system, LIMB can offer the potential for up to 70% SO_2 removal.

This technology may be capable of reducing emissions of both sulfur and nitrogen oxides at costs substantially below those of other retrofit approaches such as FGD. The Agency has recently approved the design for a wall-fired LIMB demonstration project. Construction of this 105 Mw demonstration project will begin later this year, with a start-up date for the one-year test program scheduled for June, 1987. This is a cooperative project with EPA, Babcock and Wilcox, the State of Ohio and Ohio Edison participating.

Low NOx Burners (LNB). This technology is currently available for new boilers; however, it has not been widely demonstrated on a retrofit basis. It achieves 50 to 70% NO_x control with minimal capital and operating costs. Demonstration on a sufficient number of boilers representing the full U.S. boiler population is necessary for widespread commercialization.

Reburning. Addition of secondary fuel and air above the primary combustion zone reduces NO_x exiting that zone by 50% or more. Since the capital and operating costs are also moderate, reburning can be combined with low NO_x burners to achieve total NO_x reductions of 75 to 85%. Reburning is also applicable to boilers where the use of LNB is not practical, such as cyclone boilers.

Fluidized Bed Combustion. Atmospheric (AFBC) and pressurized (PFBC) burn coal in a bed with sorbent material under conditions which reduce both SO_x and NO_x. Since an existing boiler must be rebuilt to retrofit a fluidized bed, it is an expensive technology and may have limited applicability.

Post-combustion

Most existing post combustion technology is for SO_2 control; however, some of the new processes may also provide NO_x control. Wet scrubbing is the current commercial technology for high efficiency (70-90%) control of SO_2, but is a capital intensive technology. Innovative technology must offer improved cost-effectiveness by significant reductions in capital cost and/or increases in removal efficiency. Examples are: 1) improved FGD; 2) low cost FGD systems; 3) sorbent duct injection and 4) E-SOX.

Improved FGD. Organic acid and magnesium additives to lime/ limestone wet scrubbing FGD systems have demonstrated high (95%) SO_2 removal capabilities in relatively short commercial-scale tests. These additives are used extensively in commercial applications to enhance process control and reliability, but SO_2 removal is generally set to meet minimum regulatory requirements, usually about 80-85%. Application of optimum SO_2 control to existing FGD would increase efficiency by 10 to 15% (ie, 90 to 95% SO_2 reduction) and remove a significant increment of current SO_2 emissions.

Low Cost FGD. Spray dryer FGD systems have been applied to low to medium sulfur coal electric utility applications. Since most existing coal fired electric utility boilers use electrostatic precipitators (ESPs), retrofitting a spray dryer FGD system is much less expensive than a wet FGD system if baghouses are not required. Pilot testing is currently underway at TVA and EPA to improve the SO_2 removal capability of the spray dryer/ESP combination. Chemical additives to enhance SO_2 removal and low-cost ESP upgrades are potential candidates for full-scale utility boiler demonstration test programs. The goal of this technology is a 90% SO_2 emission reduction.

Sorbent Duct Injection. Sorbent duct injection with flue gas humidification will benefit from the development of more reactive sorbents with the potential of substantial SO_2 removal without the capital costs associated with FGD hardware. Additional post-combustion capture of NO_x may be realized by addition of known sequestering agents such as sodium hydroxide or EDTA to more reactive sorbents. Under DOE's program, several promising duct injection projects are being conducted which have the potential for removing up to 70% of SO_2 at costs which are much less than conventional systems, and which produce dry, easily disposable wastes.

E-SOX. E-SOX is being developed by EPA as a low cost SO_2 removal technology to be retrofitted into boilers which use electrostatic precipitators (ESPs) for particulate control. Since nearly all plants burning high sulfur coal use ESPs, E-SOX can potentially be applied to all high sulfur coal plants and could achieve 50-70% SO_2 removal. New sorbents now under investigation may significantly reduce cost and increase the SO_2 efficiency of the process.

The schedule for commercialization of these technologies is very speculative, but assuming a full scale demonstration program, EPA believes the following schedule is possible:

1. Within 5 years: Improved existing FGD and Low NOx burners.
2. Within 10 years: Integrated LIMB, Low cost FGD, E-SOX; Duct Sorbent Injection; Reburning; and Reburning with Low Nox Burners.

As this list shows Mr. Chairman, there are several types of clean coal technologies which appear promising in the near and middle term.

With regard to a schedule for proposing acid rain controls, this Administration has stated on several occasions that "when the scientific uncertainties have been reduced, this Administration will craft and support an appropriate set of measures to solve the acid rain problem." Several critical scientific uncertainties still exist. We do not yet believe that the current state of knowledge can sustain any judgement with respect to the level of emission reductions needed to prevent or eliminate damage. This is true even for the area of greatest scientific understanding, sulfur emissions and surface water acidification. In the area of the impact of acid deposition on forests, we have yet to determine if a cause and effect relationship exists.

EPA, DOE and other government agencies have been working diligently through the NAPAP program to reduce these uncertainties, and we are making substantial progress. Funding for the acid rain research effort has increased greatly over the last several years. The emphasis on all this research has been, and continues to be the delivery of new increments of results as soon as possible so that research can have a near term influence on our ability to formulate acid rain policy and acid rain goals. This research effort is now beginning to bear fruit. The incremental answers that we will receive within the next 2 to 3 years should result in major increases in our ability to asses the needs and goals of an acid rain control program. Therefore, we believe that any regulatory approach being considered in current legislation is premature. That is why we have encouraged the Congress to postpone a decision on creating a national acid rain program until it can be based on sounder scientific information.

In response to the Committee's inquiry concerning the availability of acid rain control technology and the implementation of acid rain proposals, let me first point out that several technologies for the control of acid rain percursors are available today. If we find the scientific evidence compelling, an acid rain control program could be carried out relying on this existing technology. The point raised by the Joint Envoys in their report was that a more diverse and less expensive set of technologies would help in developing a consensus on the acid rain issue. We believe that the current DOE program, and the program that the President has committed us to through his full endorsement of the Joint Envoys report, can provide needed, less expensive control options. In reviewing the legislative proposals currently before Congress, it is uncertain whether the implementation time frames called for would facilitate the full utilization of many of the clean coal technologies which will be demonstrated through the DOE and Joint Envoys programs.

In closing, I would like to affirm EPA's support of the development of clean coal technologies being done by the private sector with the support of the Department of Energy, the Electric Power Research Institute and others. We carefully consider the status of these clean coal technology initiatives in our periodic review of New Source Performance Standards.

EPA is committed to the principle that coal can be used in an environmentally acceptable manner. We believe that advancements in pollution abatement systems will allow coal to be burned cleanly and cost-effectively.

That concludes my statement this morning. I would be glad to answer any questions that you may have.

Senator **Warner**. Thank you, Mr. Thomas.

Now we will hear from Secretary Walker.

STATEMENT OF HON. MARY L. WALKER, ASSISTANT SECRETARY FOR ENVIRONMENT, SAFETY AND HEALTH, DEPARTMENT OF ENERGY

Ms. **Walker**. Thank you.

Good morning, Mr. Chairman, members of the committee. I am pleased to be here today to discuss the——

Senator **Warner**. I wonder if the Secretary might bring her microphone forward. We are quite anxious to hear her.

Ms. **Walker**. Yes, sir. Is that better?

Senator **Warner**. Yes.

Ms. **Walker**. I am pleased to be here today to discuss the Administration's policy on acid rain and the Department of Energy's efforts to implement that policy, and in particular the Department's Clean Coal Technology Program. The status of our research on new processes and control technologies will be addressed by Donald Bauer, the Acting Assistant Secretary for Fossil Energy.

This administration has made environmental protection an important priority. It has also initiated and maintained effective and efficient energy policy. For acid deposition and its effects, the policy includes understanding the problems, determining the extent and kinds of damage, and working to improve our understanding of how various emission control programs would reduce identified damages related to acid control emissions.

While it is clear that acid rain is a serious concern, we do not yet have sufficient information in order to make a prudent decision on the need for or design of additional emission reduction authorities. Rather, the administration believes such decisions should be deferred until a more adequate scientific basis has been established.

This administration already has in place a comprehensive national research program designed to resolve the scientific issues and uncertainties associated with acid deposition and has recently set in motion a new program to assist development of practical, cost-effective technologies for the use of clean coal.

We believe the recent technologies demonstration program and other similar programs by EPA, the States, and private organizations will contribute to developing new, lower cost control options. Thus, as the envoys recognized in their report, this administration has not waited for all of the answers to act.

The current levels of sulfur dioxide emissions which lead to acid deposition have decreased since the early seventies and, based upon our review of reasonable assumptions, are likely to decrease further in the long term as a result of the existing Clean Air Act and other initiatives such as the Clean Coal Technologies Program. Growth of nitrogren oxide emissions has also slowed.

Further, although there is considerable uncertainty in emission projections, the general pattern shows no rapid growth in emissions. Thus there is time to seek the right answer before taking additional or further action.

The envoys concluded in their report if the menu of control options were expanded and if the new options were significantly cheaper yet highly efficient, it would be easier to formulate an acid control plan that would have broader public appeal.

There have been two recent Federal initiatives to expand or add programs to stimulate clean coal innovation and thus expand the menu of control options, as the envoys recommended.

The President called for increased research and development on the clean use of coal in January 1984. The commitment to this program has been substantial, totaling over $600 million for fiscal year 1985 through fiscal year 1987, and the program will continue. This core Federal program brings new technology options from concepts to demonstration and commercial application.

To extend the products of this core research and development program in effective demonstrations, Congress and the administration have provided another initiative in the past 6 months—and that is of course the Clean Coal Technologies Demonstration Program enacted last December. This $800 million plus, cost-sharing initiative has already produced proposals for evaluation.

Finally, the envoys' report proposes the expanded innovative technologies demonstration program and includes other recommendations to assist general commercial acceptance of successful technology options.

These new control development initiatives have a high potential payoff. We are already seeing the success of one new clean coal technology, the atmospheric fluidized bed process, which is a leading new technology option for coal-fired industrial boilers.

By late summer, selection of successful proposals under the Clean Coal Technology Program will be complete. Appropriate mechanisms for the full implementation of the envoys' report are also being put in place. But technology demonstrations and subsequent commercialization take time. We believe it is important to realize the results of these efforts before mandating additional controls.

Recently, various bills have been introduced that are designed to rapidly reduce sulfur dioxide and nitrogen oxide emission, but which if enacted would disrupt the demonstration programs and would reduce commercial acceptance of these innovative control options.

While our present knowledge indicates that the environmental benefits of such added control programs at this time would be uncertain, the cost to utilities and their ratepayers are generally estimated as $3 to $8 billion per year. The Department of Energy believes that other disruptions would also be caused. These include changes in energy use from patterns that would have occurred without such controls.

While the extent of possible fuel shifts has not be quantitatively estimated, the Department believes there is a potential for our energy supply to be both less secure and less affordable.

Further, these bills mandate action and choices within a short period of time, causing States, utilities, and industries to commit to specific emission reductions often within the next 2 to 3 years. Under these conditions, we are concerned that prudent planning would result in selection of today's high-cost options rather than selecting the promising but still unproven innovative technologies. Thus, the results of the new control development initiative could be lost because of a premature requirement that offers uncertain and, we believe, small environmental benefit. Likewise, we believe such legislation would become a major impediment to the Clean Coal Demonstration Programs.

Thank you. I will be happy to answer any of your questions.

[The prepared statement of Ms. Walker follows:]

TESTIMONY OF

MARY L. WALKER

ASSISTANT SECRETARY FOR ENVIRONMENT, SAFETY AND HEALTH

U.S. DEPARTMENT OF ENERGY

COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

JUNE 9, 1986

Good morning. I am pleased to discuss today the Administration's policy and the Department of Energy's efforts concerning acid rain and, in particular, the Department's clean coal technology demonstration program. The status of our research on new processes and controls will be addressed by Donald Bauer, the Acting Assistant Secretary for Fossil Energy.

Policy on Acid Rain Controls

The Administration has concluded that, although it is clear that acid rain is a serious concern, we lack information needed to make a prudent decision on the need for additional acid rain emission reduction authorities. Therefore, the Administration has chosen to defer such decisions until a more adequate scientific base is established. The Administration will act when it is reasonably certain that action will achieve intended results and these results justify the social and economic costs.

The Administration has accelerated and improved the focus of the interagency research program and is carrying out acid rain related control technology research and development. The Clean Coal Technologies demonstration Program, enacted last December, and similar programs for clean coal demonstrations by EPA, some states and private organizations will contribute to developing new, lower cost options.

The implementation of all of the Envoys' recommendations will further the process for resolving acid rain concerns. This includes facilitating general commercial acceptance of technologies that are successfully demonstrated.

The Envoys' report, in the section on the U.S. perspective, details U.S. understanding of specific forms of potential damage due to acid rain. Their statements include:

"The current number of acidic lakes is relatively small."

"It cannot be predicted what future acidification, if any, would occur if current levels of deposition were to continue."

"At this time, the relationship between acid rain and forest damage in the United States is only conjectural."

"Without (currently unavailable) quantification, it is difficult to determine the significance of acid deposition damage to building materials."

"Acid rain is not known to cause direct human health effects."

"No incidents of human health problems associated with heavy metals dissolved by acid deposition have been reported in the United States."

In summary then: benefits of acid deposition reduction are uncertain. Known damage is small.

The uncertainty here is not over details of method or administration. Rather, it concerns the most basic of policy questions: whether or not current programs are adequate to control acid rain related damage. Based on present information, there is no indication of a near-term catastrophe. Most scientific concern over the potential risk of continuing deposition at current levels is focused on the long-term, defined as decades. The few years needed to complete the research program on causes-and-effects is a relatively short period of time.

Furthermore, the current levels of sulfur dioxide emissions, which may lead to acid deposition, have decreased since the early 1970's and DOE believes they are likely to decrease further in the long term as a result of the existing Clean Air Act and other initiatives such as the clean coal programs. Growth of nitrogen oxide emissions has slowed. Recent trends in urban ambient concentrations are down from the historic highs occurring in the 1970's. Further, although there is considerable uncertainty in emission projections, the general pattern is no rapid growth in sulfur dioxide emissions, although emissions 25 years from now could have either increased or decreased somewhat from today's levels. After that, most projections of sulfur dioxide emissions show significant declines. These projections do not account fully for the deployment of innovative clean coal technologies which could further reduce the estimates of future emission levels.

Therefore, the Administration's position is well founded. It is prudent to develop, to reasonable assurance, the results of an action before acting. If time exists prior to when added impacts are expected, it is prudent to develop lower cost contingencies while the scientific base on causes and effects is being developed so that results of actions taken can be reasonably predicted.

Balancing Environmental Protection and Energy Policy

This Administration has made environmental protection an important priority; it has also initiated and maintained effective and efficient energy policy. For acid deposition and its effects, the policy includes understanding the problems, determining extent and kinds of damage, and working to improve our understanding of how various emission control programs would reduce identified damages related to acid rain emissions.

The Administration's policy recognizes that present emission control programs in the Clean Air Act have controlled and reduced emission levels of sulfur and nitrogen oxides from historically higher levels. In addition, I would like to emphasize a more recent set of initiatives related to resolution of this environmental problem. There have been three recent Federal initiatives to expand or add programs to stimulate technology for clean coal innovation.

(1) The President called for increased R&D on the clean use of coal in January 1984. The commitment to this program has been substantial, totalling over $600 million for FY-85 through FY-87, and it will continue. This core Federal program brings new technology options from concepts to being ready for use as demonstrations and in commercial application.

To extend the products of this core R&D program to effective demonstrations, the Congress and Administration have provided other initiatives in the past six months:

(2) The Clean Coal Technologies Demonstration Program, enacted by the Congress last December, is designed to demonstrate new options that will improve environmental acceptance of coal in all U.S. processes. This $800 million plus, cost-sharing initiative has already produced 51 proposals. The Federal evaluation of the proposals is underway and is to be completed by August of this year.

(3) The U.S. and Canada Acid Rain Envoys' Report proposes an expanded

innovative technologies demonstration program and includes other recommendations to assist successful commercial use of successful technology options.

These new control development initiatives have a high potential payoff. We already see commercialization of one new clean coal technology, the atmospheric fluidized bed process, which is a leading new technology option for new coal-fired industrial boilers. We applaud similar programs by states and private groups, such as the Electric Power Research Institute.

By late summer, selection of successful proposals under the Clean Coal Technology Program will be complete. Appropriate mechanisms for the full implementation of the Envoys' Report are being put in place. And, our continuing research and regulatory programs will have been reviewed for increasing opportunities for innovation and for consistency with the Envoys' Report objectives.

As the Envoys' report pointed out:

> A significant impediment to the development of a U.S. consensus on acid rain is the high cost of the available control options. Because the impacts of different options fall on different interest groups, political positions have become polarized, and it has become increasingly difficult to find a common ground for action. If the menu of control options were expanded, and if the new options were significantly cheaper yet highly efficient, it would be easier to formulate an acid rain control plan that would have broader public appeal.

Clean coal technology development is related to the acid rain issue in two ways: it supports current regulatory programs by providing improved control options, and it provides for the possibility that, if additional regulatory programs or increased control stringency is needed, there will be added viable control options. The clean coal program relates directly to technology-related regulations of new plants by providing more efficient, more economical and, generally, more cost-effective processes and controls for consideration in both regulatory and compliance decisions.

The critical feature of technology development as it relates to potential future emission control programs is the time scale for commercial acceptance. A successful demonstration, which could take 2 or more years, initiates the commercialization processes. Even completed demonstrations take time before general acceptance occurs.

Such a time scale does not match well with control schemes which must be planned and approved by 1990. If new requirements cause such rapid choice of technologies, this would induce the application of current costly and inefficient control mechanisms such as scrubbers and the substitution of lower sulfur coal for higher sulfur coal as the principal compliance methods. Yet, scrubbers are expensive, energy intensive, and produce sludge which is hard to dispose of and an environmental problem. Further, switching from high to low sulfur coal by many plants nearly simultaneously would disrupt the coal market, displace mining jobs and affect the economies of communities dependent on mining as a primary industry.

New, more efficient methods are more likely to be used when there is a substantial lead time between the planning and the implementation of use in new facilities or retrofit applications.

New Control Programs Now Are Premature

We believe that any further steps to reduce the known acid deposition damage at this time by imposing further and more stringent emission controls would have uncertain results and would lead to uncertain benefits as compared to certain large costs.

The amount and trends of damages known to be caused by acid rain were discussed earlier. They appear to be small and not increasing rapidly. We continue to be unable to predict how specific reduction patterns would reduce deposition and damage levels in sensitive areas. Based on these results, the benefits that would be gained by further emission reductions must be considered uncertain, yet where there is known damage, the benefits would be relatively small.

On the other hand, the social and economic costs associated with implementing control programs similar to those that have been proposed in various bills are likely to be high. Many of the bills would call for sulfur dioxide and nitrogen oxide emission reductions of millions of tons per year and programs that would be fully implemented in about a decade. Planning by states and industries to meet assigned emission reduction obligations often would need to be completed by 1990.

Analysis of these bills by several different groups are in general agreement. Costs to utilities and their ratepayers are generally estimated to be 3 to 8 billion per year, causing total implementation costs of tens of billions of dollars for retrofitting and operating today's control methods. These costs are based on optimization models so that actual practices could be substantially higher.

For some bills, estimates of impacts on electric utility ratepayers indicate although overall national increases might on the order of two to three percent, some ratepayers could experience bill increases of twenty-five percent or more, unless there is a subsidy program.

Environmental regulatory costs are already a major factor in electric utility decisions on plant replacement and modernization. As noted in the recent National Energy Policy Plan:

> "Compliance with air quality regulations now requires as much as 20 to 25 percent of the capital cost of a new power plant and reduces operating efficiency by about 5 percent."
>
> "Because power plants now account for roughly 85 percent of domestic coal demand, environmental regulation of those plants emissions is perhaps the single most crucial Government-controlled variable in determining the future of the U.S. coal industry."

We know that large-scale SO2 emissions reductions will reduce demand for high sulfur coal. Estimates of the decrease in demand for higher sulfur coal by Argonne National Laboratory from conditions in 1997 expected without a new bill range up to 100 million tons per year with similar increases in demand for lower sulfur coal. These reductions in demand primarily occur in Northern Appalachia and the Midwest coal areas. Opportunities for jobs lost in these high sulfur coal areas could be as high as 25,000. These losses occur in the same States required to make the largest utility and industrial boiler emission reductions.

Some bills might trigger fuel switching among fossil fuels, for example, from coal to oil and to natural gas, thus encouraging perhaps inefficient fuel choices. The extent of this switching is not estimated in the numerical analyses cited earlier and, if it occurred, it would change coal use estimates. Such fuel switching could also increase our dependence on foreign fuel supplies. Further, it could lead to higher cost and less efficient fuel choices for utilities and industrial boilers.

It appears to DOE that the proposed new program that is being done for environmental protection reasons provides uncertain, and potentially small, benefits at the cost of unjustifiably high costs and adverse impacts on energy industries and private fuel choices. The energy policies, including oil deregulation, of the past five years have been effective. We let the marketplace work and it delivered assured supplies of energy at reasonable -- often lower -- prices. Such control programs and their timing will offset and compromise consumer gains achieved by these policies.

We believe that, if one of these bills were enacted, it would pose a major impediment to the acceptance of new, lower cost control technologies demonstrated as commercially viable in the clean coal demonstration programs. Coupled with existing programs, the new demonstration initiatives are both considerable and promising. This is underway and the acceptance of the Envoys' Report has given new impetus to this process. But technology demonstration and subsequent commercializaion take time. New mandated control programs could preclude realizing the opportunities inherent in our innovative technologies programs.

Summary

Clean coal demonstrations enhance the current control programs which deal with acid rain precursors -- some technologies appear devoted to new applications but many have retrofitting or repowering application.

Clean coal demonstrations will provide for potential contingencies involving retrofit applications, especially if such retrofit requirements occur in the longer term.

The current concern over long-term risks due to acid rain, and the current uncertainty over whether or not such risks will actually result in significant additional damage, lead me to question the selection of rapid emission reductions and to strongly support the Administration's position that any added emissions reduction programs at present would be premature.

The clean coal demonstration program, together with the continuation of research on cause-and-effect, are reasonable measures for dealing with the acid rain issue at this time. Full implementation of the Envoys' recommendations, utilizing what we learn from the Clean Coal Technology Program, will provide a variety of cost-effective technologies for use in the future.

This completes my formal testimony. I will be happy to answer any questions you may have.

STATEMENT OF DONALD L. BAUER, ACTING ASSISTANT SECRETARY FOR FOSSIL ENERGY, DEPARTMENT OF ENERGY

Mr. **Bauer**. Good morning, Mr. Chairman, members of the Committee. It is also my pleasure to join the committee here at the table this morning in discussing the administration's position on acid rain and clean coal efforts and what we are doing. In the interest of time, I will also summarize my testimony.

Following Congress' direction to the Department of Energy last December, we have now augmented our basic research and development program with an effort to demonstrate the commercial feasibility of emerging clean coal technology. A total of $397.6 million is available for the Clean Coal Technology Program for fiscal years 1986 through 1988, and that amount will be matched by an equal amount from the private sponsors.

To ensure consideration of a broad spectrum of cost shared projects, the clean coal competition is open to all markets, all technologies that apply to any segment of the U.S. coal resource.

On April 18 of this year, which was the closing date for the submissions, the Department received 51 responses to that solicitation. A compilation of the abstracts submitted in response to that solicitation has been made available to the public and to members and staff of Congress.

We did something different than we normally do in solicitations. That is, we asked this time, because of the interest and importance of the solicitation, that proposers give us a public abstract which could be released to the public, so as to make the public aware of what technologies have been proposed for joint funding; in essence summaries of their proposals.

We have gone through preliminary evaluation of those 51 responses and 39 of those responses are now moving into comprehensive evaluation. We remain on a schedule to meet the congressionally mandated deadline of August 1 for selection of candidate projects.

Mr. Chairman, we are encouraged by the private sector's response. The receipt of 51 proposals confirms that American industry is prepared to devote considerable resources to advancing the technology of coal.

I recognize the committee's considerable and legitimate interest in the progress of our evaluations. However, as the Department's official for selecting of these proposals, I share Secretary Herrington's commitment to ensuring a fair and impartial review of those submissions.

I cannot at this time provide the committee with specific details of the proposals or what is happening in our ongoing evaluation, because any statements that I would make could be interpreted as a predisposition towards a technology or project.

At the time of selection, however, we will immediately provide Congress with: one, a copy of the selection statement which contains the rationale for our selection; and two, as soon as possible thereafter, we will submit to Congress a comprehensive report on the proposals that we received.

In your letter of invitation, Mr. Chairman, you raised some important questions regarding the timetables for clean coal technology demonstrations compared to those outlined in various acid rain control measures now pending before this Congress.

From our experience with previous coal technology projects, a reasonable estimate of the time required to design, fabricate, and sufficiently operate a demonstration project of this type is typically 3 to 5 years for a retrofit and 5 to 9 years for a grassroots facility.

Now, if these timetables prove applicable to the projects that are funded under the Clean Coal Technology Program, performance testing generally will not be completed until the early to mid-1990's. Even then, the speed with which the demonstrated technologies will receive full commercial use is highly uncertain. It depends upon a lot of factors.

These timetables are particularly relevant when considering acid rain control strategies, such as H.R. 4567. As I explain in my formal statement, Mr. Chairman, the timeframes in H.R. 4567 would not in my opinion permit full consideration of the technologies that will emerge in the ongoing Clean Coal Technology Program.

Instead, the Nation's utilities and those industries affected would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technology options.

In summary, Mr. Chairman, the Clean Coal Technology Program represents an important step in giving the American people and the public the information it needs to formulate a national consensus on the control of pollutants linked to acid rain.

The commercial availability of such advanced technologies could provide more efficient and economical means for implementing existing programs and authorities for the control of emissions of acid rain precursors, and it could also provide more effective options, more cost effective options, if additional emission reductions are found necessary.

This completes my formal statement, Mr. Chairman, and thank you.

[The prepared statement of Mr. Bauer follows:]

Statement of
Donald L. Bauer
Acting Assistant Secretary for Fossil Energy
U.S. Department of Energy
to the
Committee on Energy & Natural Resources
June 9, 1986

Mr. Chairman and Members of the Committee:

Clean coal technology research and development has been pursued by both government and industry since the early 1960s. Beginning in the late 1970s, however, the phenomenon of "acid rain" increased interest in developing an expanded suite of technological options to control sulfur and nitrogen oxides emitted from coal-burning installations. From Fiscal Year 1981 to the present, the Department of Energy has spent more than $2.3 billion on clean coal research and development. These programs, many conducted in conjunction with the private sector, have helped advance several new "clean coal" technologies to the threshold of commercial demonstration.

Following the Congressional direction provided to the Department last December, we have now augmented our core research and development program with an effort to demonstrate the commercial feasibility of emerging clean coal technologies. A total of $397.6 million is available for this Clean Coal Technology Program for fiscal years 1986 through 1988.

On February 17, 1986 the Department issued a "Program Opportunity Notice" which describes the program's objectives, the information requirements for prospective proposers, and the qualification and evaluation criteria that I will apply when selecting proposals for award. In accordance with Public Law 99-190, which made the funds available, the Department is requiring a minimum of 50 percent sharing of project costs by the private sector. The Department also is requiring that such cost sharing be on an "as-expended," dollar-for-dollar basis during each phase of the project.

To ensure consideration of a broad spectrum of cost-shared clean coal projects, the competition is open to all market applications of clean coal technologies that apply to any segment of the U.S. coal resource base.

By April 18, 1986, the closing date for submissions, the Department had received 51 proposals. A compilation of the public abstracts submitted by the offerors has been made available to the public and to members and staff of Congress.

We are encouraged by the private sector's response. The receipt of 51 proposals confirms that American industry is prepared to devote considerable resources to advancing the technology of coal.

At this point, Mr. Chairman, I must stress that the agency is in the midst of a competitive evaluation. We have completed the preliminary evaluation of the proposals and as a result of that review, we have determined that 39 proposals will proceed to comprehensive evaluation. We are now examining these proposals in accordance with the evaluation criteria set forth in the Program Opportunity Notice. As required by Public Law 99-190, we will select candidate projects for cost-sharing on or before August 1, 1986.

As the Department official ultimately responsible for selecting proposals for possible financial assistance under Public Law 99-190, I share Secretary Herrington's commitment to ensuring a fair and impartial review of the submissions. I cannot, at this time, provide the Committee with specific details of the proposals or our ongoing evaluation, nor can I make any statements that could be interpreted as a predisposition toward any technology or project.

In my role as Source Selection Official, it would be inappropriate for me to comment further on information contained in the Public Abstracts submitted by offerors, since any comments I might make regarding the projects discussed in those abstracts could be inaccurate (because they are not based on a thorough review of the underlying proposal) or misinterpreted (as evidence of a predisposition either for or against a particular proposal or technology).

At the time of selection, however, we will immediately provide Congress with a copy of the Selection Statement which will contain the rationale for selections. As soon as possible thereafter, we will also submit to Congress a comprehensive report on proposals received.

When the Clean Coal Technology program is complete, the demonstration projects it will have financed are expected to provide the technical, economic, environmental, health and safety, and operational information that will enable the private sector to make rational commercialization decisions.

The timetable for projects financed under the Clean Coal Technology Program will be governed by the nature and schedules of the selected proposals. In general, however, from our experience with previous coal technology projects, a reasonable estimate of the time required to design, fabricate and sufficiently operate demonstration projects of this type is typically 3 to 5 years for a retrofit technology and 5 to 9 years for a "grassroots" facility. Such timing is largely inherent in the design, construction and testing process itself and generally, additional project funding does not accelerate the demonstration schedule.

If these timetables prove to be applicable to the clean coal technology projects funded under this program, performance testing of these projects generally will generally not be completed until the early to mid-1990s. Once the demonstration project has been completed, the speed and degree to which the demonstrated technologies will achieve full commercial use is highly uncertain. In addition to assessing technical feasibility, potential users and suppliers must also consider economic conditions, applicable statutory and regulatory provision requirements, and other business-related factors that are critical to commercialization decisions.

These timeframes are particularly relevant when considering acid rain control strategies embodied in legislation currently pending in the Congress, such as H.R. 4567 which recently was approved by the Subcommittee on Health and the Environment, Committee on Energy and Commerce. Under this legislation, by January 1, 1993, the statewide yearly emissions average of all fossil fuel fired electric utility steam generating units cannot exceed 2.0 lb SO_2/mmBtu heat input. By January 1, 1997, the yearly average for utility SO_2 emissions cannot exceed 1.2 lb SO_2/mmBtu; the yearly average for utility NO_x emissions cannot exceed 0.6 lb NO_x/mmBtu; and the statewide yearly averages for non-utility steam generators cannot exceed 1.2 lb SO_2/mmBtu and 0.6 lb NO_x/mmBtu.

The timing is more constrained than these dates, however. Approved State plans for utility emissions must be done by 1990 and for industrial emissions by 1994.

The timeframes in H.R. 4567 would not permit consideration of new technologies that will emerge from the ongoing Clean Coal Technology demonstration program. If the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options.

The ongoing evaluation process will provide valuable information about the proper scope and pace of future clean coal technology-related efforts, including the Administration's response to the Special Envoys Report on Acid Rain.

As you are aware, on March 19, 1986, the President in response to that Report called for a cooperative government-industry program that will enable many of the emerging clean coal technologies to take their final steps into the marketplace. The Administration is also encouraging States to undertake similar efforts, as several have already done.

In fashioning the appropriate mechanisms for implementing the Special Envoys' Report, we will rely heavily on the information developed as part of the current Clean Coal Technology Program. The proposals submitted in response to the Clean Coal Technology Program Opportunity Notice, in essence, gives us an insight into the types of projects the private sector is interested in pursuing, as well as their scale, costs and commercial potential. This information will be an important factor in determining the most appropriate and cost-effective next steps in implementing the President's initiative.

In summary, Mr. Chairman, the Clean Coal Technology Program represents an important step in giving the American public the information it needs to formulate a national consensus on the control of pollutants that contribute to the formation of acid rain. The commercial availability of such advanced technology could provide more effective and economical means for implementing existing programs and authorities for acid rain precursor controls, and could also provide more cost-effective retrofit options in the event additional emission reductions are found necessary.

Thus, the Clean Coal Technology Program is progressing in concert with the ongoing National Acid Precipitation Assessment Program, chartered under the Energy Security Act and now in its 6th year, that is developing the analytical methods and conducting the research necessary to improve our scientific understanding of the acid precipitation issue.

Together, these efforts provide a prudent and productive approach to (1) resolving the clash of conflicting scientific views about acid precipitation and its effects; and (2) developing an expanded slate of cost-effective technologies that would be commercially available in the event additional pollutant abatement measures are necessary.

This parallel approach will ensure that the nation has sound, scientifically-credible evidence on which to base future acid rain control decisions as well as improved technological tools to meet current emission requirements and more stringent requirements should they be enacted in the future.

We believe, however, that proceeding with pollution abatement timetables beyond those embodied in the current Clean Air Act before we gain experience through the Clean Coal Technology Program will be inefficient and may prematurely eliminate promising technical alternatives that could prove more desirable in the long run.

This completes my opening statement.

Senator **Warner**. The Chair will now recognize the distinguished Senator from New Mexico to initiate the questions.

Senator **Domenici**. Thank you, very much, Mr. Chairman.

Let me ask Administrator Thomas first, with reference to the acid rain problem, have we determined whether or not powerplants, that allegedly are the major contributors to the acid rain problem, are complying with the Clean Air Act of the United States and still contributing to the acid rain problem? Or are they in noncompliance? Are some in noncompliance and contributing?

Mr. **Thomas**. Senator, I think overall the issue, particularly with sulfur dioxide, comes down to a compliance status as far as the Clean Air Act is concerned and the ambient requirements in the vicinity of the plant itself. But with respect to what the long-range transport issues are of that sulfur dioxide away from the plant itself, we are working now to implement tall stacks regulations that we put in place last year to try to deal with that issue in the requirements of the Clean Air Act itself.

But I think we are talking about largely long range transport of pollutants, and therefore compliance with the Clean Air Act, but concerns about the implications of those pollutants long-range.

Senator **Domenici**. I wonder, Mr. Thomas, if you would submit for the chairman a list of plants that are within the present zone of the United States that are perceived to be contributing to the acid rain problem that are not in compliance with the ambient standards in the United States.

Mr. **Thomas**. We can do that.

Senator **Domenici**. I think you will find that there are some that are not and they are substantial contributors. Ohio I think is the lead case in point, I'm sure, unless they have fixed it up. They sure have been.

[The material referred to follows:]

The Agency's Compliance Data System lists 690 coal and oil-fired power plants subject to State Implementation Plan requirements for SO_2. Of these 690, 30 (4.3%) are in violation of applicable SO_2 requirements. A chart showing the distribution of these plants by Region and a listing of the violating plants are enclosed.

Seven of the 30 violating plants are presently meeting the requirements of a schedule to come into compliance. Twelve of the remaining plants are located in Ohio. These plants, while not in compliance with SIP requirements, are in compliance with the Interim Enforcement Policy for Ohio, as amended on February 11, 1980 (45 FR 9101). This policy, designed to focus EPA's enforcement resources on sources of SO_2 which present the greatest threat to the environment, requires compliance with currently applicable SO_2 emission limits to be demonstrated on a 30-day rolling weighted average basis with emissions in any one day limited to 1.5 times the currently applicable emission limit.

		Regions									
Power Plants	Total	1	2	3	4	5	6	7	8	9	10
SIP Operating Plants	690	34	59	74	127	184	33	75	41	59	4
SIP In Violation	30	0	1	0	0	27	1	1	0	0	0

Source Name	Street Address	City Name	State	ZIP
Public Service Electric and Gas	Cliff Road	Woodbridge	NJ	070771
Central Illinois Public Service	Coffeen	Coffeen	IL	620171
City Water Light and Power	Stevenson Ave	Springfield	IL	627075
Illinois Power Company	Vermillion PWR PLT	Oakwood	IL	618581
Commonwealth Edison	Patterson Road	Joliet Township	IL	604355
Consumers Power Company	JC Weadock Plant	Essexville	MI	487321
Coldwater Bofp Util	28 W Chicago St	Coldwater	MI	490361
Consumers Power Company	B C Cobb Plant	Muskegon	MI	494455
Consumers Power Company	JH Campbell Plt	West Olive	MI	494605
Detroit LK Utility	1045 Roosevelt	Detroit Lakes	MN	565011

Source Name	Street Address	City Name	State	ZIP
New ULM Utility	310 N First St	New ULM	MN	56073
Willmar Utility	710 Benson Ave	Willmar	MN	562011
Rochester Utility	Silver Plant Plant	Rochester	MN	559011
St. Paul Dist Heat	78 Kellogg Blvd	St. Paul	MN	551025
Dayton Power and Light JM Stuart	P.O. Box 158	Aberdeen	OH	451011
Cleveland Gas and Light	R.R. #1 PO Box 872	New Richmond	OH	451571
Ohio Valley Electric	Kyger Creek	Cheshire	OH	456201
Cleveland Gas and Light	Brower Road	North Bend	OH	450521
Ohio Edison Toronto	Route 7 P.O. Box 307	Toronto	OH	439641
Cleveland Elec Illuminating	East Lake Plant	Willoughby	OH	449041
Cleveland Elec Illuminating	Avon Lake	Avon Lake	OH	440121
Toledo Edison	Acme Front	Toledo	OH	436041
Toledo Edison	Bayshore	Oregon	OH	431611
Ohio Edison-Gorge	E Cuyahoga Fall Ave	Springfield	OH	443101
Ohio Edison-Niles	Belmont NE	Niles	OH	444461
Dover Minicipal Light Plant	Broadway	Dover	OH	446225
Ohio Power-Muskingum	Muskingum River	Beverly	OH	457151

Source Name	Street Address	City Name	State	ZIP
Dairyland Power Genoa3	Plant #3	Genoa	WI	546321
Arizona Public Service	US 550	Fruitland	NM	874165
Iowa State Univ.	Physical Plant	Ames	IA	500101

Senator DOMENICI. Let me ask you with reference to the clean coal research, all three of you. Are we suggesting that the proposals that are going out for research are aimed at curing the acid rain problem, or are they aimed at making available technolo gy that will cause coal to be more functional as a basic power source, considering the need to comply with the Clean Air Act of the country, or both?

I mean, they are not the same, as you have just indicated, Mr. Thomas. So when you are out there looking for this new technology, are you looking for clean coal technology so that in 15 years new powerplants will have this technology and thus be cleaner as they burn coal, or are you looking at technology that has some application to clear up the acid rain problem?

Mr. THOMAS. Senator, I think probably Mr. Bauer is more capable of commenting on the existing Clean Coal Program. But my comment about the existing program, as opposed to the Lewis-Davis report's recommendations, really gets to the point you are making.

That is, you have currently got a fairly broad set of objectives for your existing program, one of which or several of which are environmental. The Lewis-Davis report was taking that from a different point. That is, they were looking at a very finite issue, which was the acid rain issue, and saying: How do we use clean coal technology to deal with that issue?

So it focused specifically on high emitting SO_2, NO_x sources, in this case also looking at transboundary sources. So it focuses its criteria in that report more narrowly, I think, than the focus of the broad Clean Coal Technology program.

Senator DOMENICI. I understand that. But what are the proposals going to yield, that or the other?

Mr. BAUER. The Clean Coal Technology Program—and I am taking my colleague's statement about the Envoys' Report—is applicable to all coals, all markets, and all technologies. Therefore, it is very broad in the total applicability. The Envoy's Report, in my mind, was talking about capacity and it was very narrow, because it addressed only high sulfur coal retrofit, utilities, and emission reductions.

So with the Clean Coal Technology Program, the $400 million program we are talking about is for all applications. And now, on the other point, in talking about the core program, the fossil R&D Program, which this Clean Coal Technology Program will augment and supplement, just the entire purpose of the R&D Program is to find ways to use coal in all markets more efficiently, economically, and in an environmentally acceptable manner.

Senator DOMENICI. So let me ask all three of you in a very specific way. Is it your conclusion, then, that the $400 million clean coal program does have a potential for significantly contributing to our Nation's capacity to control the phenomenon called acid rain?

Mr. BAUER. Yes, it does, Senator.

Ms. WALKER. Yes.

Senator DOMENICI. Do all three of you agree with that?

Mr. THOMAS. I would qualify. I agree with my colleagues that it has that potential, but I think clearly you are going to have a broader focus of the projects than the acid rain focus. I think that you may well see that more of the effort will go toward the burning efficiency goals, as opposed to the acid rain environmental goals as a general statement.

Senator **Domenici**. Let me make it clear that the Senator from New Mexico thinks they are both eminent American goals. I just want to be sure that I understand that this may not yield any significant corrective technology for acid rain. It clearly has the high probability, if the scientists and private sector are right, of yielding some new technology for the more efficient cleaner burning of American coal. As I said, both are very admirable and we should do both.

Now, let me ask, with reference to—I was not here when we had a discussion about coal versus nuclear between the distinguished minority leader and the chairman of the Committee. I am fully aware that we constantly get in these kind of arguments.

If it is not nuclear versus coal, it is natural gas versus coal. I think that is rather natural around here. But it does seem to me, with reference to the acid rain cleanup, that we ought to address the issue of select usage or, as the GAO report concluded, a market approach to cleaning up the acid rain problem, as compared with any mandated scenario.

Currently, we as a nation are involved as far as cleaning up dirty coal in our statutes with a notion that is called a percentage reduction. I assume all three of you are aware of that. It is promulgated principally by a marriage of alleged dirty coal interests—I think they are very shortsighted, because they own a lot of clean coal also—married up with environmentalists who are worried about clean coal and want it cleaned up with scrubbers, even though burned without scrubbers it meets the standards for the dirty coal with scrubbers, if people could believe that is the American policy.

It sounds rather strange, but it is true. Now, let me ask you this. Is any research being done on a so-called select use for the control of acid rain? We have indications that those who are totally promotive of coal and thus committed to coal being cleaned up with technology so as to comply with some notion that that is best for them and best for us, that that is pretty shortsighted.

We have evidence right now, for instance, that this inordinate cost that is attributed to that is causing America to move to the use of Canadian electricity. My numbers indicate that the gigawatt hours of Canadian electricity coming into the United States will go from 17.8 to as high as 35,000 gigawatt hours by 1995, almost doubling, which means we will leave them with the environmental problems and buy their electricity, which means we will use their coal, we will use their gas, but we are not going to use our coal.

Coupled with the inordinate costs of the single approach today, which is percentage reduction accompanied by scrubbers, this leads me to conclude that we are going to spend an inordinate amount of money, either the consumers are or the National Government is, to clean up this phenomenon and this problem.

And I believe we ought to set aside the disputes between gas and coal and nuclear and solve the problem. I think gas has potential for helping solve this problem.

Now, let me ask. We are aware of the potential for simultaneous combustion of coal, dirty coal, and gas, that produces energy much cleaner. We are aware of another technology, reburning, which is injecting and burning natural gas downstream from the furnace, and it cleans up the product enormously.

Currently, from what I understand that would not be permitted under the Clean Air Act itself, and obviously the Fuel Use Act does not permit it. Has anybody looked into that?

I think I could convince my friends from the coal-producing States—and incidentally, they have plenty of clean coal and plenty of dirty coal. At this point most of the mines are mining heavy sulfur coal. But I would think——

Senator FORD. Would the Senator yield?

Senator DOMENICI. I think the marriage of the two might be ideal. It would cause us to import a lot less.

Senator FORD. Would the Senator distinguish between clean and dirty coal?

Senator DOMENICI. I will not use the word any more. High sulfur content versus low sulfur. High sulfur content is generally higher in Btu's than low sulfur coal. Most western coal is low sulfur, but low Btu. You have got to burn a lot more of it.

But you know, Senator, that in your State, in the State of Ohio, there are huge amounts of low sulfur coal.

Senator FORD. We may disagree just a little bit between Kentucky and Ohio. But when you put either coal in the scrubber they come out the same.

Senator DOMENICI. That is not quite correct. A scrubber will clean up dirty coal, high sulfur coal, to meet the present ambient standards. But if you put clean coal in, you do not measure what comes out of the smokestack. You measure how much you have reduced the sulfur content of the clean coal that went in.

And if you do not reduce it by the percentage mandated in the statute, you cannot put it in there even if it is coming out cleaner.

Senator FORD. You still have the sludge that creates the problem.

Senator DOMENICI. You have that in any event, Senator, I assume. I really am not opposed to anything you are for. I am trying to find a solution that will cause us to use more coal and mix it, if that is an approach, and to use different technologies, than the absolutely apparent approach that we are going to put scrubbers on all of this to clean up coal so that in some way the clean coal gets cleaned up even more and the high sulfur coal gets cleaned up to meet the new source performance standards.

Senator FORD. I agree with you on the select use. There is no question about that.

Senator DOMENICI. Is anybody prepared to comment on that, or is that irrelevant to the situation?

Ms. WALKER. If I understand the questions or some of the things you focused on, the Department of Energy is certainly committed to making the fuels available to the marketplace in such a manner that they are environmentally acceptable and they can compete, and certainly that, in the Clean Coal Technology Program is one of its objectives, and certainly an objective of the Department concerning other matters as well.

And hence, the support of the repeal of the Fuel Use Act and certain other steps which the Department has taken. You asked about studies. I think the studies are available and we could supply them for the record.[1] I do not have the precise analysis for you today, but we can certainly get that for you.

Senator DOMENICI. Mr. Bauer.

Mr. BAUER. I agree with you when you were talking about the triad, the coal, nuclear, and natural gas, and we add in conservation. But I think one of the ways of having the market approach, as you were discussing, is to go ahead as proposed, with the natural gas deregulation and repeal the Fuel Use Act. Then proceed on with our base coal R&D program and select the projects under this Clean Coal Technology Program. The public has the data upon which to make decisions then.

Senator DOMENICI. Perhaps I could make my question very much simpler, since apparently I was not very much understandable. Are the research projects and the studies with reference to acid rain cleanup assuming the continued existence of the Fuel Use Act as presently on the books or not?

Because if you assume they are going to be there, you will not be studying some of the hybrid approaches to cleaning up the problem. You will assume it is against the law.

Ms. WALKER. It is my understanding the studies are available both with the assumption of the repeal of the Fuel Use Act and without it, that is to assume its continued existence. The studies that I referred to we can provide you with.

Senator DOMENICI. Mr. Thomas, I have written to you asking you if your Department and cadre of experts would explore the select use approach, where you are not prohibited from mixing fuels like gas and coal in an effort to solve these problems.

Is something being done by way of evaluating that as a potential?

Mr. THOMAS. Senator, we are reviewing it as far as our policy analysis is concerned, what are the various options that may be available, regardless of what our regulatory restrictions may be, then to come back and look at what the implications are for possible modifications, such as possible modification of the statute, possible modification of regulations.

So from a policy analysis point of view, I think we are reviewing the issue you raised. The only thing from a hard research point of view I think that would be tied into our engineering program would be that related to reburning technologies, NO_x control, which is the possibility of using natural gas downstream from coal-fired plants for further reductions of NO_x.

We do have as part of our research program some work underway on that, as does the DOE.

Senator DOMENICI. I wonder if you might submit for the record a summary of that kind of research that is going on with reference to that specific, both the Department and the agency. Could you do that?

Mr. BAUER. Yes, sir.

Mr. THOMAS. Yes, sir.

[The material referred to follows:]

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[1] Subsequent to the hearings the Department of Energy submitted two reports: (1) "Powerplant and Industrial Fuel Use Act", Annual Report dated March 1, 1986, and (2) "The Natural Gas Policy Act Amendment of 1986." Both reports were retained in committee files.

Committee on Energy
and Natural Resources
U.S. Senate
Date: June 4, 1986
Witness: Donald L. Bauer
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REBURNING TECHNOLOGIES

One of the major areas of interest in the Fossil Energy Research and Development Program on Flue Gas Cleanup is NO_x control. To date work in this areas has focused on combustion modification (air staging) and flue gas treatment. Both approaches have now been commercialized. Air staging is a low cost technique but has limited potential (50-60% NO_x control maximum). Flue gas treatment, on the other hand, offers high effectiveness but with costs that are presently considered prohibitive in the U.S. In addition, this approach has been plagued with operating problems. More recently, increased emphasis has been placed on another combustion mouification approach termed variously reburning, fuel staging, or in-furnace NO_x reduction. The process involves the injection of fuel into the combustion products followed, after a suitable residence time, by the addition of air at a somewhat lower temperature (100°C) to complete the combustion process. It has been found that modifying the combustion process in this manner destroys NO_x contained in the original combustion stream. Although the exact mechanisms of NO_x destruction are not well understood, it has been postulated that the NO_x reacts with free radicals present in the fuel rich combustion zone to form molecular nitrogen.

Reburning is currently being evaluated in both the U.S. and Japan. Experimental results suggest that the combustion of reburning with conventional air staging can result in NO_x reduction levels approaching those now attainable only by flue gas treatment processes at much higher costs. The reburning process is a very complex one. NO_x reduction potential appears to be a function of a relatively large number of process parameters including temperature, relative fuel split between the primary combustion zone and the reburning zone, primary and reburning zone air-to-fuel ratios, gas residence time in the reburning zone, as well as the nitrogen content of the reburning fuel. If not correctly implemented, NO_x can actually be generated in the reburning zone from the reburning fuel-bound nitrogen. In addition, the potential exists for reducing combustion efficiency as the result of incomplete fuel combustion. It would appear that to realize the full potential of this technology, further research is required to better define the mechanisms involved, pinpoint the free radical species of primary interest, and perhaps investigate techniques to enhance the generation of these free radical species.

In FY 1986, a thorough evaluation and assessment of this technology is being performed. On a more basic level, the mechanisms and processes that lead to the formation and transformation of sulfur and nitrogen compounds resulting from the combustion of coal-based fuels are being studied as a portion of advanced research in the combustion process itself. Both types of compounds are believed to be precursors of acid rain formation. Sulfur and nitrogen are introduced into the combustion process as elements contained in the fuel. Nitrogen is also an element contained in air used as the source of combustion oxygen. Both cause acid rain-related contaminants, primarily oxides. Fundamental research is underway to determine the chemical processes and to measure the kinetic rates involved in the formation of nitrogen and sulfur oxides as functions of the parameters controlling the combustion environment. Such variables include temperatures (which vary throughout the combustion volume), pressure, source of contaminant, particle size distributions in the coal-based fuels, amount of air admitted, and time duration of combustion.

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Research is simultaneously underway to explore the mechanisms and rates involved in various means of reducing the deleterious effects of these contaminants by using control procedures in-situ during the combustion process. Studies have included the nitrogen oxide-reducing techniques of both air and fuel staging during combustion and the use of in-situ sorbents to act as sulfur "getters".

These fundamental investigations of the formation and transformation of pollutants and means of controlling them are within a continuing program. Underway for several years, it will continue in FY 1986 and FY 1987.

Insert For
Page 72
Mr. Thomas

Congressional Record Insert: The EPA NO_x Reburning Program for
Acid Rain Hearings on June 9, 1986

Early fundamental studies of NO_x destruction by injection of secondary fuel into the flame zone were performed by J.O.L. Wendt et al., who coined the name "reburning" to describe the process. Concerted effort to develop reburning for application to boilers occurred in Japan during, the late 1970's and early 1980's. Japanese results indicate that NO_x emissions can be reduced by at least 50 percent independent of initial NO_x level on fuel type. These promising results have renewed interest in reburning, and further development is being sponsored by the U.S. Environmental Protection Agency (EPA), the Electric Power Research Institute (EPRI), the Gas Research Institute (GRI), and the U.S. Department of Energy (DOE).

Since 1982 EPA has carried out both in-house and extramural bench- and pilot-scale reburning tests. In-house experiments have focussed on natural gas and fuel oil reburning. Coal reburning tests, as well as natural gas reburning of coal primary flames, have been performed for EPA by Energy and Environmental Research Corporation. Significant findings include that reburning effectiveness is dependent on primary flame NO_x level, reburn zone stoichiometry and reburn fuel nitrogen content. Fifty percent NO_x reduction is possible with 10 to 20 percent of the fuel diverted for downstream reburning injection. However, at low initial NOx levels, a nitrogen-free reburning fuel (such as natural gas) must be used to achieve 50 percent reduction. It has been shown that reburning is effective over a wide range of temperatures and with a relatively small residence time. In larger scale applications mixing rates of the staged fuel and air become increasingly important. Many EPA publications are available describing both the in-house and extramural research.

An RFP has been issued by EPA to apply reburning to an industrial or small utility coal-fired boiler using natural gas as the reburning fuel. This work will be co-sponsored by GRI and EPRI, beginning in September 1986 and lasting 3 or 4 years. DOE has received at least one reburning proposal in response to their Clean Coal Technology Program. Therefore, there is potential to coordinate the EPA and DOE efforts to cover a wide range of reburning applications.

Senator WARNER. Thank you, Senator.

I am going to make one brief observation and then turn to Senator Ford here. We have listened this morning very carefully on this issue. I wonder if we should not touch on the automobile as a contributor. Nitrogen oxides, I believe, are also a part of acid rain.

Mr. Thomas, what would you say to the American driver out there that might be watching this particular hearing?

Mr. THOMAS. There is no question that autos, trucks, buses, any of our mobile sources, are major targets as far as nitrogen oxide emissions are concerned. And as a result, the United States has the most stringent mobile source emission program in the world.

The regulations that I put in place, oh, about a year ago on heavy duty trucks and buses set out standards all the way out to the mid-1990's for reductions that are aimed at particulate matter, and also nitrogen oxides. We have very stringent controls as far as nitrogen oxides are concerned and will continue to have on trucks, buses, light duty trucks, in addition to cars that now have standards up through the 1990's.

Senator WARNER. I am well aware of the standards. But to what extent can we point our finger at the vehicle contributor to the acid rain?

Mr. THOMAS. I do not have that figure right offhand as to what contributing portion they are beyond the stationary sources. I guess I would conclude, though, that there is going to be very little additional gain from additional controls over those sources.

Senator WARNER. I am not suggesting any additional controls. I am suggesting vehicles do contribute to this problem of acid rain.

Mr. THOMAS. I think 30 to 40 percent is a good figure, equivalent to the 30 percent we talked about with powerplants, as far as NO_x is concerned.

Senator WARNER. Did you wish, Secretary Walker, to add anything to that issue?

Ms. WALKER. No, I would add that it's about 40 percent. Thank you.

Senator WARNER. Senator Ford.

Senator FORD. Mr. Thomas, I wish you would get to the Metrobuses. I am not clear if it is clean, but boy, when they start up and you are behind them, it is tough. I wish you would get to them. It is right here at home. You start here.

Mr. THOMAS. We have set a standard for 1990 for buses.

Senator FORD. I hope we live that long. [Laughter.]

I try not to lose my good humor and I hope you will not, either.

I want to ask this question and see which one of you would dare answer it. I want one of you to look me in the eye and for the record tell me whether you believe the administration will, in fact, meet its commitment to implementation of the Joint Report of the Special Envoys on Acid Rain. [Laughter.]

Ms. WALKER. May I ask the Senator, are you looking for a simple yes or no?

Senator FORD. Well, things are not simple around here, young lady. If you want to give me an answer you are not prepared to give, it takes a long time. But if you are prepared to give a yes or no, I certainly will accept it.

Ms. **Walker**. I feel the Senator should have an answer and I would not want you to think that we have a reluctance to give one. I can tell you what I know and believe to be true. That is, that the administration has endorsed the Envoys' report and has made a good-faith commitment to carry out the recommendations in it, recognizing that it is a multistage process—that is, we have already begun the Clean Coal Technology Program and want to see its results before we move forward in another action and want to see the results of the research before we move forward for additional controls.

I think the Envoys recognized we did not have all the answers. The Envoys recognized what they were really trying to do is to bring the two countries together and working together on a mutual problem. So when we say that—when you ask is the administration going to carry out the Envoys' report, we say yes, recognizing that there are some unknowns in that as even the Envoys recognized.

And so I think the answer is yes; it is a good faith commitment. I do not know perhaps what specifics you might have in mind, but, yes.

Senator **Ford**. Go ahead.

Mr. **Thomas**. Senator, I would agree with that. I spent a lot of time with the Envoys before that report was put together, working through the issues, particularly with Drew Lewis, and I have spent a lot of time since on working on the implementation of the Envoys' report with the caveat of whether the full amount of money is going to be needed or requested, which is largely dependent, I think, about what's out there as far a private sector commitment to those kinds of technologies and what we will find out from this first phase clean coal. I do not think there is any question that the administration is committed to full implementation of that report.

Senator **Ford**. When do you think we will have the details of the plans from the administration to implement the program?

Mr. **Thomas**. Well, for instance, there are three big components. One component was the Acid Rain Research Program. I chair the interagency panel that overviews acid rain research. We have already moved to implement those components.

Another one is the full regulatory review of existing regulations for possible reductions. I have an interagency work group that is working on that right now. The consultation process between the two countries that cut across a range of issues has been put in place by the Secretary of State and as a matter of fact I believe next week an interagency group led by the Department of State will be going to Canada to confer with their colleagues in Canada. The final component, which is the clean coal technology component, in the Department of Energy is proceeding as they have indicated to develop proposals for clean coal technology.

So the implementation phase of that report is well underway.

Senator **Warner**. If the Senator would yield, what about the $5 billion price tag?

Ms. **Walker**. I am sorry, Mr. Senator?

Senator **Warner**. The $5 billion price tag; are you prepared to come up here and ask for that money?

Ms. **Walker**. Well, I think what we have said is that we are prepared to ask for funds when it becomes prudent to do so. We have an initial $400 million program that Mr. Bauer has described and he has indicated the status of that. We believe we need to see the industry participation in that and some of the fruits of that before we come back and ask for more. So I think at the proper time, yes. But what we want to see is what we have got on board now and how that——

Senator **Warner**. What is the attitude of OMB about spending more money?

Ms. **Walker**. I would want to let OMB speak for itself.

Senator **Ford**. They usually tell you what to say, do they not, when you get down to the time of talking about money. I have got a couple more questions, Mr. Chairman.

But, Mr. Bauer, we advised your staff of the question I was going to ask so that you could follow it up. I hope you have the paper there. But it is from one of tomorrow's witnesses on page 9 and 10.

Under the program opportunity notice, the PON as it is referred to, the statement comes on pages 9 and 10 that the following summarize EPRI's preliminary assessment of the April 1986 response to the PON's relative to the electric utility applications. The 51 proposals submitted are less than one-third the number of clean coal demonstration projects identified to DOE a year ago. Many were apparently canceled because of the discouraging requirements in the PON relative to the private sector's understanding of the original congressional intent.

Second, the areas of least response relative to the opportunities identified originally appear to be in the retrofittable emission control options, particularly lower cost engineered plant modifications.

The following summarizes this preliminary observation by technology category. It is not intended to reflect in any way on the quality of specific proposals for which there appear to be very worthwhile examples in each category. It is on retrofittable emission control options. clean coal, limited response; combustion modification, limited response; fuel gas desulfurization, very limited response: Responses on new plant options, AFBC, strong response; PFBC, strong response; coal conversion, limited response; fuel cells, strong response.

A simplified and unambiguous, "short form" PON would encourage the retrofit emission control options which are notably absent in the response. They are especially important to reduce cost if further emission reductions become necessary for existing plants.

So if the push as I see it has been to retrofit, I would appreciate your views of his estimate of the program opportunity notices.

Mr. **Bauer**. My reaction to the EPRI testimony is as follows: First of all, last year we had statements of interest and informational proposals that we sought from industry. It is true we had 171 responses. But of those responses, some of them were general statements of just interest in it and some were less than 50-50 cost sharing. So when you look at the public abstracts on the section 321 response, there were only 35 of those that were informational proposals on emerging clean coal technologies of 50-50 cost sharing. So that was our statements of interest.

When we went out with our solicitation for project proposals, and we had 51 proposals that came in for which we released public abstract statements. So I am encouraged by that.

Also of the proposers responding to the solicitation of statements of interest last year, about 45 of those people, responders that responded last year, also submitted proposals under this one. So that shows a good correlation. And by the way I am doing a correlation based upon the public abstracts under clean coal and the statements of interest before. I have not touched the proposals so I do not know if there is a true correlation of one to one between the public abstract and the proposal.

Two other points. Of the 51 proposals, it is true that about a third of those are for retrofit application; out of the 51, a third. For the utility industry, if you are talking about new and retrofit probably a third of them are for the utilities.

No. 3, there are 10 technologies included in the public abstracts and apparently included in the proposals. I came up with 10; there is another category I cannot identify because it is either a combination of two different technologies or they did not really say in their public abstracts.

So all of those technologies are identified. And if we go to the application of technologies and look at utility, industrial, light industrial and commercial, and the transportation markets, we find that several of the technologies have both applications for new as well as retrofit.

And the final point, I do not necessarily agree with the adjectives on some of the characterizations like strong response, in my reading of the abstract.

Senator FORD. It is the verbs and nouns I am interested in.

Mr. BAUER. Well, "strong response" on fuel cells, in my reading of the public abstracts I did not come up with a "strong response."

Senator FORD. OK. Speaking of abstracts, is there any reason why this Senator could not get a copy of those abstracts?

Mr. BAUER. I would be glad to give you a copy of those public abstracts. And besides, last week I believe it was, Senator, there were three that we had not gotten previously because the proposer had——

Senator FORD. I have yet to get any.

Mr. BAUER. You will get it today, guaranteed.

Senator FORD. And that is on the record.

Mr. BAUER. That is on the record. [Laughter.]

Senator FORD. You know what I am going to do, Mr. Bauer? I am going to shift.

[The documents are given to Senator Ford.]

Senator FORD. I hate to take your staff's copy. It is probably their only copy. [Laughter.]

Mr. BAUER. I worked with staff over the weekend, and I think they may be under an energy shortage.

Senator FORD. Mr. Thomas, let me ask this question and then I will tell you why I am asking the question, and this will be my last one.

Why is 1980 used as the base year in cleanup legislation? Why not 1976, when the Clean Air was implemented? I want to read some of my letter to Mr. Waxman.

The States that did something early about clean air are penalized by every proposal now before the Congress. Kentucky is a good example. In 1976 when the Clean Air Act was put fully in place, Kentucky sulfur dioxide emissions were 1.54 million tons. By 1980 emissions were reduced to 1.11 million tons, a 430,000-ton cleanup. Emissions have been further reduced in 1985 to 878,000, a reduction from 1980 of some 232,000 tons. Kentucky is credited with these 232,000 tons under legislation pending but not the earlier 430,000 tons made in 1976–80 since full implementation of the Clean Air Act. We get penalized for 4 years and 430,000 tons.

So why is 1980 used and not 1976?

Mr. THOMAS. If you will give me just a minute, Senator.

Senator FORD. I will be glad to let you huddle with anybody you want to. [Pause.]

Mr. THOMAS. The 1980 figure you were referring to, Senator, is the bill out of that particular legislation?

Senator FORD. Every one of them.

Mr. THOMAS. We are working on an update now of a figure for 1985. The 1980 figure that we used, just as we have used figures in the past, year by year, is not a figure that we have supported or opposed as far as any legislation is concerned. Maybe I could give you a more detailed answer for the record where I could give you the basis for our 1980, as well as what we have done since to update those figures.

Senator FORD. This is fine. But I am going to submit a question to you in writing—Mr. Chairman, and I will not go any further today—asking you to take the 1976 base, but end up at the same place that the Waxman bill does.

Mr. THOMAS. As far as overall reduction?

Senator FORD. Right.

So if you go back to 1976, those States that implemented and were able to reduce some would then get equal treatment; those that did not are really getting a break, as I see it, and as I understand it. I think it is awfully hard to convince me otherwise.

Mr. THOMAS. Senator, it is a little different concept in that bill, you know, than has been used in a lot of others. It is an emission rate approach as opposed to an overall percentage reduction approach which looks at overall emissions, looks at coal burned or energy used and comes up with an overall emission rate. As a matter of fact, it takes a 2- and a 1.2-point average as the goals over the next 8 years, 7 or 8 years, with a phasing approach.

So actually that bill is a little different than say one of the ones that was recently introduced over on the Senate side and tries to take into account an emission rate approach to take into account changes in a State more so than say struggling with a base year and then working from it as far as a reduction is concerned.

Senator FORD. Well, we will use the Senate bill.

Mr. THOMAS. The Senate bill is a good example of one that takes that base year and says let us go a 10- 12-million-ton reduction from it. So the base year, as you indicate, has a tremendous impact as far as what is required in individual States.

Senator FORD. So let us take that. And I would like you to—and I will give you this in writing—but to alert you that it is coming, I want the States that are penalized as a result of it and States that are being given a break, but using 1976 as a base year.

Mr. THOMAS. We would be glad to answer it.[2]

Senator FORD. Thank you, Mr. Chairman.

Senator Warner. Thank you.

Mr. Administrator, on behalf of the chairman who has not yet been able to return, I would ask the question: To what extent is the decision to extend the life of an existing facility influenced by regulatory policies? For example, as the chairman understands the EPA regulation, at a certain point the costs of retrofitting an existing facility become great enough that it runs the risk of being classified as a new one, subject to the new source performance standards over the percentage now related to 50 as established by regulation, not by law.

Would you comment?

Mr. THOMAS. It is a regulatory requirement, the 50-percent reconstruction of a facility, thereby qualifying it as a new source, although there are number of criteria that go along with that.

As I looked at that issue and pushed on it with policy staff, I did not come out of it with a feeling that that was a primary motivating factor for life extensions. I think regulatory requirements for environmental controls obviously are a factor, but I did not get the sense that that was a primary factor as far as life extensions are concerned. How much it plays one way or the other I think is probably very plant specific.

Senator WARNER. Chairman McClure indicates here in this memorandum that he is not advocating a shift. But if you were to reduce this percentage, would an incentive shift from life extension in favor of new construction occur?

Mr. THOMAS. I think probably for some plants, that would be a factor.

Senator WARNER. Chairman McClure is also quite anxious, since this committee has the jurisdiction of the Clean Coal Technology Program and the Interagency Task Force on Acid Rain Research, the chairman requests, and is indeed joined by the ranking minority, that you keep this committee fully informed of the progress that takes place.

Mr. THOMAS. We would be pleased to do that, Senator.

Senator FORD. Mr. Chairman, I do have four questions for Mr. Bauer that I will submit to you in writing, Mr. Bauer, to bring us up to speed with the Appropriations Committee.

Senator WARNER. On behalf of Chairman McClure and the members of this committee, we thank this distinguished panel. You have contributed greatly to an increased understanding of this problem.

We will now have a second panel, and we will take about a 2-minute recess while they take their seats. [Recess.]

Senator WARNER. The second panel will consist of Mr. Dave Berger, coal director, Ohio Coal Development Office; Mr. Michael D. Greer, chairman, West Virginia Public Power Commission; and Ms. Terri Moreland, manager, Illinois Coal Development Program.

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[2] See responses to questions 16-18 in appendix I.

We welcome you and thank you for joining us today, and we will lead off with Mr. Berger.

STATEMENT OF DAVID BERGER, DIRECTOR, OHIO COAL DEVELOPMENT OFFICE, DEPARTMENT OF DEVELOPMENT

Mr. **Berger**. Mr. Chairman, I will make abbreviated remarks. I have provided the staff with testimony and I would like to address two fundamental points.

First, the role of clean coal technologies in acid rain controls, and to offer some guidelines to promote the development and the application of these technologies to abate acid rain.

From a national perspective, clean coal technology has been defined to include coal beneficiation, retrofit technology, repowering alternatives, and coal conversation processes. All are appropriate options when viewed as means to expand the clean use of domestic coal.

However, in the context of prospective acid rain controls and the joint envoys' report, only retrofit options that achieve net sulfur and nitrogen emission reductions are worthy of serious consideration. In large measure, this translates into technology options that are applicable to existing coal-fired facilities. While the field of these promising and emerging clean coal technologies is large, options currently proven out at utility applications for high-sulfur coal are extremely limited.

I will not go into a comparison of coal beneficiation and scrubbers, except to add that perhaps neither offers an optimal solution. Our particular circumstance in Ohio is having a rather large and diverse inventory of coal-fired facilities with a total of 31 coal-fired stations in Ohio that contain some 117 individual boilers, and those account for in excess of 23,000 megawatts of generating capacity. Those boiler characteristics, ratings, types, ages, and their siting circumstances area as diverse as in any State.

While scrubber systems may prove feasible and cost effective for some units, they cannot be considered a realistic option for a majority of Ohio's units. Other options which can be more easily installed and achieve significant emission reductions at the cheapest cost per ton must also be available.

Most of the clean coal technologies share several characteristics, particularly those that can be considered as retrofit technologies. First, few are singly capable of attaining 90 percent sulfur removal from high sulfur coal. Hence, it is important to recognize that two options, often in combination, may be necessary to achieve substantial emission reductions.

Second, most of the emerging retrofit clean coal technologies are lower in capital and operating costs than conventional scrubbers. This is a key consideration in weighing alternatives for older units.

Third, few have been sufficiently developed or demonstrated to substantiate reliability and effectiveness at the scale required for utility units or for the variety of utility units currently in use.

These retrofit clean coal technologies have an obvious and significant contribution to make in the control of acid rain. They offer promise for clean use of high-sulfur coal at a cost-effectiveness level well below that for scrubbers as measured in dollars per ton of SO_2 removed.

However both time and financial support are required to speed their development. Accordingly, it is strategically important to accommodate and provide incentives for their development and use in any acid rain control program considered by Congress. Congress is likely to enact a national acid rain control program within several years. Less expensive, more efficient pollution control technologies will be needed to meet mandated emission reductions.

I would like to close with at least laying out four particular points as to how these emerging retrofit, clean coal technologies could be better supported in acid rain legislation.

The first point to make is a point about timeliness. Generally speaking, from 5 to 10 years of development effort is still required to prove out these retrofit clean coal technologies. Obviously, the timeline is somewhat elastic, depending on the level of funding dedicated to this task and the speed with which reductions must be achieved. Nevertheless, any program mandating substantial reductions from existing sources prior to 1995 is likely to preclude serious consideration of nonconventional emission reduction technologies.

Second, a point about incentives. In the short run, increased financial support and incentives for utility sponsorship of clean coal technologies is clearly warranted. I would point out that the combined resources of Ohio and the U.S. DOE now dedicated to this effort fall short of the capital cost estimated for the installation of scrubbers on Ohio Power's Gavin plant alone. Additional financial support for clean coal technologies is needed and we still await the administration's proposals for the $2.5 billion in Federal support required to meet the joint envoys' recommendation.

Equally important is that utilities currently have little to no incentive to aggressively pursue and support development of these technologies. Indeed, U.S. DOE's requirement to repay clean coal technology funds from net operating revenues of supported projects constitutes a very real disincentive. Acid rain control legislation must also carry incentives for the election of innovative emission-control technologies. Otherwise, risk factors and unfamiliarity associated with these systems is likely to preclude their serious consideration. These incentives should take two forms.

First, emerging clean coal technologies should be eligible for Federal cost-sharing support.

Second, flexibility must be incorporated into the emission requirements set for these installations, should the technology fall short of achieving the reduction target. This could be achieved by allowing additional time if the standard is to be met using alternate technology.

The third point about emission standards. The type and level of emission standards to be set in acid rain control legislation are also crucial to the application of clean coal technologies. Generally, moderate percent reduction targets or tons of $S0_2$ removed are more compatible with the performance expectations for emerging clean coal technologies. Standards set on the basis of uniform pounds of sulfur dioxide per million Btu are totally insensitive to the percent reduction required of individual units or of a State as a whole.

A second perspective is the desirability of a single standard to be achieved at some certain date. The real effect of a staged, increasingly more stringent standard is often to compel investment decisions toward systems that achieve the last-stage emissions standard to meet the first milestone date. This translates into major capital investment and manpower utilization toward conventional technologies, leaving scant resources to support alternative technologies required to meet a later standard.

The fourth and final point is the compliance approach. And I will briefly sum that up by saying we very much would prefer to deal with a bubble as opposed to unit-by-unit approach in setting those standards.

This concludes my oral remarks. Thank you, Mr. Chairman.

[The prepared statement of Mr. Berger follows. The report "Ohio Coal Develolpment Agenda" submitted by Mr. Berger has been retained in committee files.]

TESTIMONY OF DAVID BERGER

Director, Ohio Coal Development Office
Department of Development

State Of Ohio

Before the

Senate Energy and Natural Resources Committee
Oversight Hearings on Clean Coal Technologies and

Strategies for Acid Rain Control

U.S. Senate

June 9, 1986

Mr. Chairman, members of the Committee, I am David Berger, Director of the State of Ohio Coal Development Office. It is my pleasure to appear before the Committee today and offer Ohio's views on the relationship between acid rain control measures and clean coal technologies.

I should like to direct my remarks toward four distinct perspectives:

1. Ohio's stake in the acid rain/clean coal technology debate;
2. Ohio's own clean coal technology initiative;
3. The role of clean coal technologies in acid rain controls; and,
4. Guidelines to promote the development and application of clean coal technologies to abate acid rain.

1. Ohio's Stake in the Acid Rain/Clean Coal Technology Debate

Ohio has an enormous stake in the shape of acid rain control and clean coal technology programs now being debated in Congress. As the nation's leading source of sulfur dioxide emissions, Ohio will be called upon to do more and pay more than any other state under prospective acid rain control programs. We have a sincere concern for our native coal industry and the communities whose economies depend on coal mining. Already, production levels are one-third less than in the early 1970's, and its future is perilled by the prospect of accelerated fuel switching.

Ohio is prepared to shoulder its fair share of national sulfur dioxide reductions. None of the proposed measures in this or preceding sessions of Congress adequately address these concerns. Most significantly, reduction levels required of Ohio far exceed its contribution to national emission loadings. Furthermore, the timelines proposed and emission levels mandated provide little opportunity for emerging clean coal technologies to make a significant contribution.

Ohio's prior commitments and actions with regard to air quality improvement also condition our perspective. Today, because of Clean Air Act requirements, Ohio's annual sulfur dioxide emissions are twenty percent less than in 1975. This 651,000 ton per year sulfur reduction is more than double the combined reductions of all of New England and New York since 1975, and, during this same period, increases in sulfur emissions have occurred in Maine, New Hampshire, Vermont and Connecticut. Further, Ohio's ambient sulfur dioxide monitoring network, the most extensive in the United States, has recorded no violations of the National Ambient Air Quality Standards since 1979. Moreover, Ohioans have spent more than $2.0 billion on the installation of particulate and sulfur dioxide controls, more than any other state. More recently, Ohioans, through a constitutional amendment referendum, have committed $100 million to the development of clean coal technologies. Ohio now has the largest state clean coal technology program in the United States.

Mr. Chairman, Ohio is prepared to move forward with additional sulfur dioxide reductions under a fair national control program. Key provisions sought by Ohio, as set forth by Governor Richard F. Celeste before the U.S. House of Representatives Subcommittee on Health and Environment on February 17, 1984, include:

- Job protection through the requirement for cost-effective technology control measures;

- Fairness and affordability through a national control program of fair emission reduction targets among the states and federal cost-sharing;

- Coverage of all compliance costs, both capital and operating through federal cost sharing; and

- Effectiveness in diminishing the acid rain problem by incorporating all sources of acid rain precursors and by relating emission reductions to the most acid sensitive regions.

2. Ohio's Clean Coal Technology Initiative

It is clear to Ohioans that the future of Ohio coal production rests squarely on the development and application of clean coal technologies. We are preparing for the rapid deployment of cost-effective sulfur dioxide and nitrogen oxide reduction controls that can be economically applied and operated on existing coal-fired utility and industrial boilers.

Support of clean coal technology has been a key priority and initiative of Governor Celeste. In his first two biennium budgets, appropriations to support clean coal technology development have doubled, from $4 to $8 million. At his urging and with strong bi-partisan support, the Ohio General Assembly enacted legislation establishing the Ohio Coal Development Office as the focal point for clean coal initiatives. Governor Celeste also played a key role in securing a 64 percent approval majority of the electorate for Ohio's $100 million clean coal ballot initiative this past fall.

Ohio's clean coal technology effort is in many respects parallel in purpose and approach to that established by Congress in the past year. They both:

- seek private sector initiatives through cost-sharing commitments of public funds;
- are directed toward near-term applications by emphasizing technology demonstrations at full-scale in user settings;
- seek to expand technology options available for sulfur and nitrogen control from existing coal-fired facilities; and
- include a competitive solicitation and selection process.

There is also one major difference between the two programs. Ohio's program, unlike its federal counterpart, provides incentives to utility sponsorship and host site support. U.S. DOE's requirement to repay funds received from the net operating revenues of the project constitutes a major impediment to utility involvement and sponsorship. This is especially so with regard to the demonstration of innovative control technologies at existing coal-fired facilities that do have net operating revenues.

Ohio has taken a different tack. Our program seeks to accelerate the development of clean coal technology and reduce the risk to utilities in sponsoring these demonstrations. In addition to $100 million in grant cost-support, utilities may also submit projects for rapid cost recovery (i.e., every six months) from our Public Utilities Commission. This additional incentive was signed into law by Governor Celeste on April 5, 1986. The opportunity to receive rapid cost recovery for utility clean coal research and development also significantly reduces risk to utility sponsorship. Hence, Ohio utilities may opt for either or both forms of support for worthy clean coal technology demonstrations.

Ohio is now in its third year of support to public/private clean coal technology demonstrations. Some sixteen separate projects are already underway or completed involving some $7.6 million in state funds and over $23.0 million in private and other public monies. Our largest project is the demonstration of limestone injection multi-stage boiler (LIMB) at Ohio Edison's Edgewater station in Lorain, Ohio. This project seeks to achieve simultaneous 50% or greater reductions of sulfur dioxide and nitrogen oxides. It also enjoys significant cost support from U.S. EPA, Ohio Edison and Babcock & Wilcox.

I am also pleased to report to this Committee the status of Ohio's recent solicitation of projects to be supported from its November, 1986, $100 million initiative. Over 175 proposal abstracts for coal research and development were received. Of that number, some 15 proposals seek concurrent State of Ohio/U.S. DOE support. Nearly one-third of all proposals received by U.S. DOE via its solicitation came from Ohio.

Although not a part of my testimony, I have with me today a limited supply of the Ohio Coal Development Office's annual Ohio Coal Development Agenda. It includes a more detailed presentation of the Office's purposes, programs and projects than is appropriate to discuss today.

3. The Role of Clean Coal Technologies in Acid Rain Control

From a national perspective, clean coal technology has been defined to include coal beneficiation, retrofit technology, repowering alternatives and coal conversion processes. All are appropriate options when viewed as means to expand the clean use of domestic coal.

In the context of prospective acid rain controls and the Joint Envoys' Report, only retrofit options that achieve net sulfur and nitrogen emission reductions are worthy of serious consideration. In large measure, this translates into technology options that are applicable to existing coal-fired facilities. While the field of these promising and emerging clean coal technologies is large, options currently proven out at utility-scale applications for high sulfur coal are extremely limited.

Commercially available technology options include coal cleaning and flue gas desulfurization. Unfortunately, neither is an optimal solution. Coal cleaning, while economically efficient and applicable to nearly all coal, is limited in effectiveness to only pyritic sulfur removal. Consequently, the upper limit of conventional or advanced cleaning of Ohio coal is not likely to reduce sulfur in raw coal by more than 50 percent. Conversely, scrubbers are quite effective in removing over 90 percent sulfur removal from flue gases. Unfortunately, they represent the most costly option and cannot be considered universally applicable to all existing coal-fired facilities.

Ohio intends to expand the array of clean coal technologies applicable to existing coal use facilities. Our pursuit of options is motivated by several factors. First and foremost, the electrical generation facilities that Ohioans depend on now and in the future are already substantially in-place. Twenty years from today, Ohio's electrical needs will still be 90 percent dependent on coal-fired generation in existence or under construction today. Repowering is simply not in the planning horizon of most Ohio investor-owned utilities.

Ohio's existing inventory of coal-fired facilities is large and diverse. A total of 31 coal-fired stations in Ohio contain some 117 individual boilers which account for 23,553 MW of generating capacity. Ohio's boiler characteristics (ratings, types, ages) and siting circumstances are as diverse as in any state. While scrubber systems may prove feasible and cost-effective for some units, they cannot be considered as a realistic option for a majority of Ohio's units. Other options which can be more easily installed and achieve significant emission reductions at the cheapest cost per ton removed must also be available.

One major constraint to the application of scrubbers is unit age. Put simply, older units with a short remaining economic life do not justify the rapid amortization by the rate-payers of expensive scrubber systems. Nearly one-third of Ohio's existing coal-fired generating capacity today is in units 25 years of age or older. More significant, however, is that 75 of Ohio's total of 117 units fall within this age population.

A second major constraint to scrubbers is unit design and/or physical site constraints that preclude their installation. A recent survey of Ohio utility stations discloses that 12 of Oh'o's 26 coal-fired units under 25 years of age, representing 25 percent of Ohio's coal-fired generating capacity, have significant degrees-of-difficulty for the retrofit application of scrubber systems. Ohio Edison's Sammis Plant provides the most graphic illustration of these constraints. Just one year ago, a one-half billion dollar particulate control system was dedicated at this plant. To accommodate this equipment, a superstructure deck was constructed over the four-lane U.S. Rt. 7 immediately next to the Ohio River. There is literally no space available for additional controls.

If coal cleaning cannot be effective enough and scrubbers are not appropriate, then what options remain? This is the niche to be filled by the development of retrofit clean coal technologies. These technologies include various types of pre-combustion cleaning, during combustion sulfur capture and post-combustion flue gas treatment systems as profiled below:

Pre-Combustion

- Conventional coal cleaning
- Advanced coal cleaning
- Coal blending

During-Combustion

- Limestone injection multi-stage burning (LIMB)
- Atmospheric fluidized bed combustion (AFBC)
- Low SO_x/NO_x burners/combustors

Post-Combustion

- Dry spray dryer scrubbing
- In-duct scrubbing
- Advanced wet scrubbing

Most of these technology options share several characteristics. First, few are singly capable of attaining 90 percent sulfur removal from high sulfur coal. Hence, it is important to recognize that two options, in combination, may be necessary to achieve substantial emission reductions.

Second, most are lower in capital and operating cost than conventional scrubbers. This is a key consideration in weighing alternatives for older units. Third, few have been sufficiently developed or demonstrated to substantiate reliability and effectiveness at the scale required for utility units or for the variety of units currently in use.

These retrofit clean coal technologies have an obvious and significant contribution to make in the control of acid rain. They offer promise for the clean use of high sulfur coal at a cost-effectiveness level well below that for scrubbers [$/ton SO_2 removed]. However, both time and financial support are required to speed their development. Accordingly, it is strategically important to accommodate and provide incentives for their development and use in any acid rain control program considered by Congress.

Congress is likely to enact a national acid rain control program within several years. Less expensive, more efficient pollution control technologies will be needed to meet mandated emission reductions.

4. Guidelines to Promote Development and Application of Clean Coal Technologies to Abate Acid Rain

Ohio will play a major role in developing new technologies, but the future contribution of clean coal technologies to solving acid rain rests largely with the Congress. If these technologies are to have a significant role, then Congressional leadership for policies sympathetic to and supportive of their development and application is needed.

I would like to conclude my remarks by setting forth guidelines that would, in part, substantially increase the contribution of clean coal technologies in acid rain control legislation. I offer four interdependent options for the Committee's consideration. They provide a framework for achieving a greater degree of interrelationship between support for clean coal technologies and action on control of acid rain.

Timelines

Generally speaking, from 5 to 10 years development effort is still required to prove out clean coal technologies for utility retrofit applications. Obviously, this timeline is somewhat elastic depending on the level of funding dedicated to the task and the speed with which reductions must be achieved. Nevertheless, any program mandating substantial reductions from existing sources prior to 1995 is likely to preclude serious consideration of non-conventional emission reduction technologies.

Incentives

In the short-run, increased financial support and incentives for utility sponsorship of clean coal technology demonstrations is clearly warranted. To provide perspective on this view, I would point out that the combined resources of Ohio and the U.S. DOE now dedicated to this effort fall short of the capital cost estimated for the installation of scrubbers on Ohio Power's Gavin Plant alone. Additional financial support for clean coal technologies is needed and we still await Administration's proposals for the $2.5 billion in federal support required to meet the Joint Envoys' recommendation.

Equally important is that utilities currently have little to no incentive to aggressively pursue and support development of these technologies. Indeed, U.S. DOE's requirement to repay Clean Coal Technology funds from net operating revenues of supported projects constitutes a very real disincentive.

Acid rain control legislation must also carry incentives for the election of innovative emission control technologies. Otherwise, risk factors and unfamiliarity associated with these systems is likely to preclude their serious consideration. This should take two forms. First, emerging clean coal technologies should be eligible for federal cost-sharing support. Second, flexibility must be incorporated into emission requirements set for these installations should the technology fall short of achieving the reduction target. This could be achieved by allowing additional time if the standard is to be met using alternative technology.

Emission Standards

The type and level of emission standards to be set in acid rain control legislation are also crucial to the application of clean coal technologies. Generally, moderate percent reduction targets or tons of SO_2 removed are more compatible with the performance expectations for emerging clean coal technologies. Standards set on the basis of uniform pounds of sulfur dioxide per million Btu are totally insensitive to the percent reduction required of individual units or a state as a whole.

A second important perspective is the desirability of a single standard to be achieved at some certain date. The real effect of staged, increasingly more stringent standards is to compel investment decisions toward systems that achieve the last stage emissions standard to meet the first milestone date. This translates into major capital investment and manpower utilization toward conventional technology, leaving scant resources to support alternative technologies required to meet a later standard.

Compliance Approach

Generally, compliance approaches that offer flexibility to states and operators of coal-fired facilities in meeting emission reduction standards are preferred over unit specific requirements. In this regard, an emission bubble concept is particularly attractive. Approaches of this type enable states and companies to elect the most cost-efective units and least costly technology options to meet the emission target.

This concludes my testimony. I wish to thank you for the opportunity to appear before you and the timeliness of convening oversight hearings into these important matters.

DB1/1.42
May, 1986

Senator MURKOWSKI [presiding]. Thank you, Mr. Berger. I am just curious. You may have the answer. To what extent is the industry looking toward new technology to make major breakthroughs in scrubbers and other devices or do you face a cost/benefit diminishing return every time you crank up the technology?

Mr. BERGER. Mr. Chairman, there is a crossover point. I suspect the industry would respond to that in mils per kilowatt hour. Should the retrofit technologies prove too expensive, there will be a decision probably made to repower rather than to retrofit, particularly where site circumstances run up the cost of a retrofit.

Senator MURKOWSKI. And that retrofit is not the new technology?

Mr. BERGER. What we are attempting to pursue, Mr. Chairman, are the types of new technologies that could be applied in existing stations. So I would distinguish the technologies according to whether they be retrofit or whether they be repowered—repowering defined as being new plant.

Senator MURKOWSKI. Our next witness is Mr. Michael Greer, chairman of the West Virginia Public Power Commission.

You may proceed, sir.

STATEMENT OF MICHAEL D. GREER, CHAIRMAN, PUBLIC POWER COMMISSION OF WEST VIRGINIA

Mr. GREER. Good morning. Thank you, Mr. Chairman. My statement has been submitted for the record and I would summarize it.

Senator MURKOWSKI. It will be entered in the record.

Mr. GREER. I appreciate this opportunity to represent the Public Service Commission of West Virginia by testifying in these oversight proceedings on clean coal technology development and strategies for acid rain control.

As a utility regulator in an energy-producing State, I have the opportunity to regularly review and consider utility construction planning, fuel purchasing strategies, supply and demand forecasting, power pooling agreements, and interutility marketing activities, all of which may be significantly affected by Federal actions on air quality restrictions and new technology incentives.

The primary concern which I have and which I want to bring to your attention is the tremendous impact on electric rates that proposed sulfur dioxide and NO_x emission limitation timetables will have.

Within West Virginia there are 13 major electric generation facilities owned by utility companies. These 13 plants provide 14,620 megawatts of electricity and are capable of producing over 120 billion kilowatt-hours of electrical energy at maximum output and utilization levels. At present our generating plants are operating at less than their maximum capacity; however they are still producing at a rate of nearly 78 billion kilowatt-hours annually. Consumption of electricity within West Virginia however is only 25 billion kilowatt-hours. Thus a very large portion, about 70 percent of West Virginia generated power, is transported to neighboring States.

I believe the coal-fired electric utility sector has been responding and will continue to respond to environmental concerns. Speaking for West Virginia—and I am confident that our record is not unique—electric utilities have responded positively to the requirements of the Clean Air Act. Our two newest generating stations emit less than 1.2 pounds of sulfur per million. Older stations have converted to lower sulfur coal and are substantially below 2 pounds of sulfur per million Btu's burned.

In 1976, West Virginia measured sulfur levels ranging from 18 to 64 micrograms per cubic meter with an average of 35. By 1985 the State average was 18 milligrams or a reduction of 49 percent in average sulfur levels for the period. During that time we added new generation, increasing coal-fired generating capacity by 2,600 megawatts or 22 percent. If we look at emissions rather than measurements, our record is equally good. In 1975 utility sulfur emissions totaled 1.3 million tons. By 1984 this had been reduced to 871,000 tons or a 33 percent reduction.

The cost of reducing sulfur emissions from existing facilities is high. If our utilities do not respond by prematurely retiring any of the existing West Virginia capacity, we would have to bring 11,760 megawatts into compliance. If we did this totally through retrofitting of existing wet scrubber technology, the estimated capital outlay would be $2 billion.

Interest, return on equity, depreciation, and taxes on capital investment would initially add an additional $700 million per year to the cost of electric generation. In other words, a total scrubber technology response to H.R. 4567 would add about $1 billion per year to the cost of generating electricity in West Virginia. This would amount to an increase of approximately 1.2 cents per kilowatt-hour, and that, as you know, would be a substantial increase anywhere.

However, rather than a scrubber-only strategy, fuel shifting may be a part of any compliance strategy. My staff has prepared some alternative cost estimates based on the availability of sufficient low sulfur fuels to accommodate 50 percent of a compliance strategy.

At this, the estimated cost in West Virginia would be approximately $650 million or 84 cents per kilowatt-hour, on total West Virginia generation. That would equate to a 14 percent increase in residential rates and approximately a 21 percent increase in industrial rates.

This morning I appear before you as a utility regulator. I do not profess to be an expert on emerging clean coal technology. However there is a clear connection between expectations for future utility costs and the success of clean coal technology development which will draw the attention of utility regulators.

I am convinced that there is a very real conflict between new technology development and a headlong rush to reduce sulfur emissions pursuant to some of the acid rain proposals presently being considered. The timetables for control that we would be faced with under H.R. 4567, for example, would require an immediate commitment to a least-cost strategy based on existing technology.

Massive amounts of capital would be committed to retrofitting existing utility boilers and to contracts for high cost low sulfur fuels. These commitments, which would heavily burden electric utility customers in those States will stifle the ability or desire of the private sector to research and develop new technologies. Forcing the millions of dollars of capital into scrubbers, will divert resources and preclude subsequent investment in clean coal technology by the electric utility industry, yet the retrofit programs are but a short-term solution, considering the age and relatively short lives of existing plans.

I would urge you to act favorably on funding and other incentives for research and development of new coal combustion technologies. Beyond that, I would urge you to not check such development by mandating a quick fix on existing electric utility generation. Clean coal technology will become a major casualty of the acid-rain controversy unless you in the Congress provide for a flexibility in planning and implementing which will allow usage of our abundant coal resources.

Thank you.

[The prepared statement of Mr. Greer follows:]

STATEMENT OF

MICHAEL D. GREER

CHAIRMAN, PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

Before the

SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

Dirksen Senate Office Building

Washington, D. C.

June 9, 1986

Mr. Chairman and Members of the Committee:

I appreciate this opportunity to represent the Public Service Commission of West Virginia by testifying in these oversight hearings on clean coal technology development and strategies for acid rain control. As a utility regulator in an energy producing state, I have the opportunity to regularly review and consider utility construction planning, fuel purchasing strategies, supply and demand forecasting, power pooling agreements and inter-utility marketing activities, all of which may be significantly effected by Federal actions on air quality restrictions and new technology incentives. The primary concern that I have and which I want to bring to your attention is the tremendous impact on electric rates that proposed SO_2 and NO_x emission limitation timetables will have.

You should be aware that a large increase in the cost of producing electricity in West Virginia will be felt not only in my State but also in surrounding states. Our electric generating plants deliver enough power to Ohio to serve 1,980,000 average residential customers in that state. Exports to Pennsylvania are sufficient to serve 1,275,000 average residential customers. Similarly, our exported power can serve 1,160,000 average residential customers in Virginia, 705,000 in Maryland and 127,000 in Tennessee. Other, more distant states, including New Jersey and North Carolina receive smaller amounts of West Virginia produced electricity.

Within the state there are 13 major electric generation facilities owned by utility companies. Some of these utility companies serve customers in W.Va., and some do not. These 13 plants provide 14,620 megawatts of capacity and are capable of producing over 120 billion kilowatt-hours of electrical energy at maximum output and utilization levels. At present our generating plants are operating at less than their maximum capacity, however they are still producing at a rate of nearly 78 billion kilowatt-hours annually. Consumption of electricity within West Virginia is 25 billion kilowatt-hours. Thus, a very large portion, about 70%, of West Virginia generated power is transported to neighboring states. The effect on the utility owned generating stations within the state will be felt not only by State residents, but also by consumers in other states as they import West Virginia produced power.

Table 1 summarizes data related to the 13 fossil fired, utility owned, generating plants in West Virginia including their capacity, initial in-service date and SO_2 emission levels. Table 2 describes recent West Virginia power production, domestic sales and exports to other states.

As a regulator, I strongly encourage you to recognize the economic effect of present acid rain proposals, particularly H.R. 4567. I believe the premature move to reduce SO_2 and NO_x emissions will increase American dependence upon foreign sources of energy, make American industry less competitive and cost thousands of American jobs. An emission requirement such as that contained in H.R. 4567 will cause a massive disruption in the economic efficiency of the electric utility industry by accelerating various schedules at vastly increased costs. Electrical energy capacity planning, retirement of older units, economy transactions between utilities in various regions of the country and least cost utilization of available capacity will be disrupted. We will be forced into otherwise uneconomic decisions: to abandon existing, useful, efficient generating units, to prematurely begin construction of new generating facilities, to reduce the efficiency of existing generating stations by switching to new coal supplies and to further reduce the efficiency of these, and other, generating units through the addition of costly, power consuming compliance technology.

The coal fired electric utility sector has responded to environmental concerns. Speaking for West Virginia, and I am confident that our record is not unique, electric utilities have responded positively to the requirements of the Clean Air Act. Our two newest generating stations emit less than 1.2 pounds of SO_2 per million BTUs.

Older stations have converted to lower sulfur coal and are substantially below 2.0 pounds of SO_2 per million BTUs burned. We are cleaning up our environment under the Clean Air Act at a reasonable pace that is documented by air quality data.

In 1976, West Virginia measured SO_2 levels ranging from 18 to 64 micrograms per cubic meter. The average was 35. By 1985, SO_2 levels had been reduced to a range from 10 to 26 micrograms per cubic meter. (W.Va. Air Pollution Control Commission, 1985 Annual Report, p.51). The state average was 18 mg/cm or a reduction of 49% in average SO_2 levels for the period. Within the same period, two generating stations were added increasing our coal fired generating capacity by 2,600 MW, or 22%. Looking at emissions rather than measurements, our record is equally good. In 1975 utility SO_2 emissions totaled 1.3 million tons. In 1984 the emissions totaled 871,000 tons, a reduction of 429,000 tons, or 33%.

The decisions to retrofit our older generating units in West Virginia for further SO_2 control will be very difficult. By 1997 five plants will be 40 years old or older, seven plants will be 30 years old or older. They represent 39% of our generation capacity. These units are capable of operating efficiently and effectively for the next 15 to 25 years. Under normal conditions they would be phased out slowly within that time frame. To spend hundreds of millions of dollars on scrubbing technology on these plants does not seem feasible. Accelerated emission standards will force many utilities to make uneconomic decisions to accomplish within 10 years, goals that would have been attained in the absence of such accelerated standards in 15 to 25 years, and at a much lower cost to electric consumers. Some will be converted at great cost, others will be prematurely retired at even greater cost.

COSTS TO WEST VIRGINIA -- SCRUBBER TECHNOLOGY

The cost of reducing SO_2 emissions from existing facilities is high. If our utilities do not respond by prematurely retiring any of the existing West Virginia capacity, we would have to bring 11,760 MW into compliance. If this were totally accomplished through retrofitting of existing wet scrubber technology to this capacity, the estimated capital outlay would be 3 billion dollars. Interest, return on equity, depreciation and taxes on capital investment of this magnitude would initially add over 700 million dollars per year to the cost of electric generation in West Virginia. Even though the total net cost on capital investment would slowly decline as capital is recovered through the depreciation allowance, the average capital related cost over the first five years after scrubbers are installed would be approximately 660 million per year. Added to the capital-related cost would be between 260 and 300 million dollars in annual operating costs for maintenance and reduced efficiency of our generating units. In total, a scrubber technology response to H.R. 4567 will add about 1 billion dollars per year to the cost of generating electricity in West Virginia. (Table 3).

The utility owned electric generating facilities in West Virginia produce approximately 78 billion kilowatt-hours per year. An additional one billion dollars in generating costs equates to over 1.2 cents per kilowatt-hour. I can assure you that a 1.2 cent per kilowatt-hour electric rate increase is huge, and would be considered as such anywhere in the country.

In West Virginia, the average residential electric rate is 6 cents per kilowatt-hour. An increase of 1.2 cents per kilowatt-hour would raise residential electric bills by 20 percent. Industrial customers are paying around 4 cents per kilowatt-hour. The 1.2 cent increase would equate to 30 percent for these customers.

I remind you that West Virginia residents would not be the only customers affected. Of the 78 billion kilowatt-hours generated in West Virginia, 54 billion is exported to surrounding states. West Virginia production costs are assigned to those states through a variety of pricing and allocation mechanisms of the state regulatory commissions and the Federal Energy Regulatory Commission. A 1.2 cent per kilowatt-hour increase will shift 688 million dollars of cost onto those interstate deliveries of power, to be added to the electric bills of customers in Ohio, Pennsylvania, Virginia, Maryland, Tennessee, New Jersey, North Carolina and others. Even though West Virginia ratepayers would experience increases of 20 to 30 percent if we were forced into scrubber technology on all existing non-compliance utility generation, such increases would pay only 312 million of the 1 billion dollars annual compliance costs.

COST TO WEST VIRGINIA -- FUEL SWITCHING AND SCRUBBER TECHNOLOGY

The report on H.R. 4567 prepared by the Office of Technology Assessment (OTA) estimates resulting West Virginia residential rate increases ranging from 9 to 13 percent. The Temple, Barker & Sloan (TBS) study prepared for the Edison Electric Institute (EEI) projects West Virginia residential increases of 14.5 percent and 21.4 percent for our two major electric utilities. The variance between our own estimates, the OTA estimates, and the EEI estimates reflects the multitude of options that are possible responses to current acid rain proposals. My initial comments on costs addressed the scrubber technology-only scenerio. Alternatives include fuel shifting from high sulfur coal to low sulful coal, natural gas and oil. The EEI study, and I assume the OTA study, expect substantial compliance through fuel shifting. My staff is concerned that the availability of economically attractive low sulfur fuels is not as great as would be necessary to accomodate some of the alternatives presented to you. (Note: I present the scrubber-only option not because it is the most likely, but in an attempt to establish the range of costs. However, this calculation does not represent the maximum because no NO_x conversion costs are included. The uncertainty and lack of data make a reasonable calculation impossible.)

The EEI study anticipates fuel shifting in the range of 50 percent for compliance purposes. My staff has prepared some alternative cost estimates based on the availability of sufficient low sulfur fuels to accomodate 50 percent of our non-compliance capacity (Table 4). At a cost differential from existing fuel costs equivalent to 10 dollars per ton, the capacity that could be shifted to low sulfur fuel would incur annual costs of at least 0.4 cents per kilowatt-hour. This would change the estimates of annual operating costs in West Virginia from 1 billion to approximately 650 million dollars. This cost would amount to .84 cents per kilowatt-hour on total West Virginia generating costs. A cost increase of .84 cents per kilowatt-hour in electric rates would still equate to an average residential increase of 14 percent and an average industrial rate increase of 21 percent. In addition to these increases to West Virginia residents, 448 million dollars per year would be added to the cost of West Virginia electricity transmitted to other states.

I believe this estimate to be conservative, not only because of our concern for the availability of sufficient low sulfur coal but also because of the $10 per ton cost differential. The sudden increase in the demand for low sulfur coal that would accompany Federal legislation such as is now being considered could result in a greater cost differential.

CLEAN COAL TECHNOLOGY:

I appear before you as a utility regulator. I do not profess to be an expert on emerging clean coal burning technology. However, there is a clear connection between expectations for future utility costs and the success of clean coal technology development which will draw the attention of utility regulators. I thought it promising that the Department of Energy reported to the Congress last year that flue gas cleanup proposals for the clean coal technologies fund were "... targeted to large utility boilers." It was disappointing, however, that in the same report the DOE concluded that Federal incentives will not accelerate commercialization of these technologies. The DOE report correctly points out that considerable research and development may be required to advance new clean coal technologies to readiness for demonstration and evaluation of commercial application. Clearly, commercialization cannot occur before research and development and an acceleration of research and development will require federal assistance.

I am convinced that there is a very real conflict between new technology development and a headlong rush to reduce SO_2 emissions pursuant to some of the acid rain proposals presently being considered. The timetables for control that we would be faced with under H.R. 4567, for example, would require an immediate commitment to a least cost strategy based on existing technology. Massive amounts of capital would be committed to retrofitting existing utility boilers and to contracts for high cost lower sulfur fuels. These commitments, which would heavily burden electric utility customers in those states which will logically be the future sites of new coal burning generating plants, will stifle the ability or desire of the private sector to research and develop new technologies. Forcing the millions of dollars of capital into scrubbers will divert resources and preclude subsequent investment in clean coal technology by the electric utility industry. Yet the retrofit programs are but a short term solution considering the age and relatively short lives of existing plants.

I would urge you to act favorably on funding and other incentives for research and development of new coal combustion technologies. Beyond that, I would urge you to not check such development by mandating a "quick fix" on existing electric utility generation. Clean coal technology will become a major casualty of the acid-rain controversy unless the Congress provides for a flexibility in planning and implementation which will allow usage of our abundant coal resources.

TABLE 1

WEST VIRGINIA UTILITY OWNED FOSSIL FUEL STEAM GENERATING PLANTS

Plant	Gross Generation Capacity MW	Original Construction Year	SO2 Levels lbs./MMBtu
American Electric Power System:			
Philip Sporn	1,106	1950	1.7
Kanawha River	439	1953	1.3
Kammer	714	1959	7.3
Mitchell	1,632	1971	2.6
John Amos	2,933	1971	1.3
Mountaineer	1,300	1979	1.0
Allegheny Power System:			
Rivesville	142	1943	1.6
Willow Island	243	1949	2.1
Albright	292	1952	2.6
Fort Martin	1,107	1967	3.0
Harrison	1,920	1972	4.7
Pleasants	1,252	1980	.9
Virginia Electric Power Company:			
Mount Storm	1,671	1965	2.8
Total West Virginia	14,751		

TABLE 2

WEST VIRGINIA ELECTRICITY PRODUCTION AND USE
1984

	Mwh	Mwh
Power Generated in West Virginia		77,950,000
Power Used in West Virginia:		
Sales to W. Va. Consumers	19,106,000	
Sales to W. Va. Utilities for Resale	2,454,000	
Company Use and Unaccounted For	2,186,000	
Total Used		23,746,000
Excess Generation Over Use		54,204,000
Interstate Deliveries by W. Va. Electric Utilities:		
Ohio	20,204,000	
Pennsylvania	13,000,000	
Virginia	11,800,000	
Maryland	7,200,000	
Tennessee	1,300,000	
New Jersey	500,000	
North Carolina	200,000	
Total		54,204,000

TABLE 3

COST OF RETROFITTING ALL NON-COMPLIANCE WEST VIRGINIA GENERATION

			Annual Costs		
Plant	Capacity MW	Total Capital Expenditures 000$	Capital 000$	Operating 000$	Total
John Amos	2,933	733,250	179,646	69,659	249,305
Harrison	1,920	480,000	117,600	45,600	163,200
Mount Storm	1,671	417,750	102,349	39,686	142,035
Mitchell	1,632	408,000	99,960	38,760	138,720
Philip Sporn	1,106	276,500	67,743	26,268	94,011
Fort Martin	1,107	276,750	67,804	26,291	94,095
Kammer	714	178,500	43,733	16,958	60,691
Albright	292	73,000	17,885	6,935	24,820
Willow Island	243	60,750	14,884	5,771	20,655
Rivesville	142	35,500	8,697	3,373	12,070
Totals		2,940,000	720,301	279,301	999,602

TABLE 4

COST OF RETROFITTING AND FUEL SHIFTING
WEST VIRGINIA GENERATION

Calculation based on 50% fuel shifting and 50% scrubber technology retrofitting.

	Low Sulfur Fuel Cost Differential			
	\$5/Ton	\$10/Ton	\$15/Ton	\$20/Ton
Fuel Shifting Costs	.2¢/Kwh	.4¢/Kwh	.6¢/Kwh	.8¢/Kwh
Total Annual Cost of Shifting 39,000,000 Mwh	\$ 78,000,000	\$156,000,000	\$234,000,000	\$312,000,000
Total Annual Cost of Scrubber Technology - 39,000,000 Mwh	499,801,000	499,801,000	499,801,000	499,801,000
Grand Total Annual Cost	\$577,801,000	\$655,801,000	\$733,801,000	\$811,801,000
Average Cost per Kwh	.74¢/Kwh	.84¢/Kwh	.94¢/Kwh	1.04¢/Kwh

Senator **Murkowski**. Mr. Chairman, I wonder if I might ask a question at this time?

The **Chairman** [presiding]. Surely.

Senator **Murkowski**. I am curious as to the tenor of the testimony of the witness, particularly with regard to the proposed requirements and the fact that coal has different sulfur contents. What happens if a supplier of low-sulfur coal, does he have to meet the same emission standards in the burning of the coal as those that supply high sulfur coal?

Mr. **Greer**. Yes, sir. At the present time no consideration is given to the kind of coal or the quality of the coal.

Senator **Murkowski**. No consideration is given to the kind of coal? Is that what you are saying?

Mr. **Greer**. Essentially. Now we have, and have for some of our power plants in West Virginia, received certain waivers to allow higher emissions to be burned. But we have many of our plants that are presently burning about 1.2 sulfur level.

Senator **Murkowski**. What is the justification for having the inequity of the same requirement as opposed to lesser requirements for lower sulfur coal?

Senator **Murkowski**. Are the requirements on the technology or are the requirements on the emission?

Mr. **Greer**. They are on the emissions, and I am not responsible for enforcing the air quality standards. But there is a consistent standard throughout the State which must be met. And if you burn a lower sulfur coal more cleanly, you are going to pay more for that. On the other hand, if you——

Senator **Murkowski**. I am sorry. I am confused now. You say if you burn a lower sulfur coal, you are going to have to pay more for emission control?

Mr. **Greer**. The cost of that coal is more expensive than the higher sulfur coal.

Senator **Murkowski**. Granted.

Mr. **Greer**. For emission control, the reverse would tend to be true.

Senator **Murkowski**. The reverse would be true?

Mr. **Greer**. Yes, sir. If you are burning low sulfur coal cleanly, then there should be little expenditure required to meet the proposed sulfur standards. However, my understanding is that to meet the proposed NC_x standards, there will be a great increase in conversion standards with the low-sulfur generating plants.

On the other hand, the utility boilers which are burning lower sulfur coal at the present time, most of them in West Virginia, are scrubbing and through the existing scrubber technology they are meeting the same compliance air quality standards.

The **Chairman**. But the compliance is on control technology.

Mr. **Greer**. Yes, sir.

The **Chairman**. Not upon emissions.

Mr. **Greer**. The compliance I am talking about is the air quality.

The **Chairman**. The Federal air quality standard. The Federal air quality standard is technology based.

Mr. **Greer**. Yes.

The **Chairman**. Not emissionsbased. It is what you do to it rather than what you achieve in doing it. Is that not correct?

Mr. GREER. Yes, sir; it is.

Senator MURKOWSKI. Well, Mr. Chairman, my question is: Under the proposed regulations that we are considering in the oversight, would it be detrimental to the low-sulfur coal producers any more, with the idea if you are going to remove the sulfur, the first 40 percent is easier to remove than the next 60 percent, but if you are comparing high-sulfur coal and low-sulfur coal, do you have to remove the same percent on the first cut?

I am trying to get a theoretical application of what the regulations are, whether they actually discourage the use of low-sulfur coal because the additional cost of compliance makes it less competitive with high-sulfur coal. [Pause.]

Senator MURKOWSKI. It was suggested by staff that the question should be rephrased as to whether it involves new construction or conversion of older plants. Perhaps that would be helpful in clarifying my question. I am curious to know whether we are doing anything as a disincentive to low-sulfur coal producers.

The CHAIRMAN. Would the Senator yield for a question or a comment, I am not sure which it is, because I think I understand what the Senator is getting at and perhaps the witnesses are not so certain what he is trying to get at.

The debate has gone on whether or not the strategy should be devoted to the final emissions level and whether the use of low-sulfur coal as a strategy is a permissible strategy or whether the parties who burn low-sulfur coal are going to be required to use the same technology to clean it up as those who use high-sulfur coal.

Senator MURKOWSKI. So far so good, Mr. Chairman.

The CHAIRMAN. So far so good. Maybe I should quit right there. Because if indeed low-sulfur coal has to use exactly the same control technology as high-sulfur coal, regardless of the emissions that come from the two plants, then it is thought by some that indeed since the low-sulfur coal costs more to get to the plant, that there is an economic disincentive to use low-sulfur coal——

Senator MURKOWSKI. It is a difference in Btu.

The CHAIRMAN [continuing]. Because there is no difference in the kind of control technology that must be used between the two.

Mr. GREER. Senator, perhaps I am not the witness to respond to this question because I am not an expert in the technology. Perhaps one of the other panelists could better answer that question.

Senator MURKOWSKI. Mr. Chairman, I have to go Chair the Senate.

The CHAIRMAN. Can either of the other two witnesses at the table answer the question?

Mr. BERGER. Mr. Chairman, to offer an observation based on my understanding what we are operating with for new facilities via the last amendments to the Clean Air Act is a requirement to apply best available control technology, irrespective of coal sulfur content, although the percent reductions are on a sliding scale, depending on that coal sulfur content.

The CHAIRMAN. So the same technology is used in either plant, at the current time?

Mr. BERGER. That is my understanding, Mr. Chairman.

Senator MURKOWSKI. So that would act as a disincentive to low-sulfur coal?

The **Chairman**. Whether it is a disincentive or a lack of incentive perhaps could be argued.

Senator **Murkowski**. Well, I have not got time to argue that now, Mr. Chairman. To me they are synonymous.

The **Chairman**. Thank you very much, Senator. I appreciate your willingness to take the gavel while I was necessarily absent.

We still have one witness to hear from.

Ms. Moreland.

STATEMENT OF TERRI MORELAND, MANAGER, COAL DEVELOPMENT SECTION, ILLINOIS DEPARTMENT OF ENERGY AND NATURAL RESOURCES

Ms. **Moreland**. Thank you, Mr. Chairman.

I am very happy to be here on behalf of the State of Illinois, where we have a lot of high-sulfur coal. Our coal industry is very vital to our State's economy, and that is why in Illinois we have as a State maintained a very active clean-coal technology development program for over a decade.

We have already provided over $55 million in State funds for cost-shared, clean-coal technology research and demonstration projects and over all our projects in Illinois represent $400 million, approximately, worth of research and development when the State funds and the funds invested by private industries, utilities, research organizations, universities, and the Federal Government are taken into account.

We have in Illinois specifically focused our program on ways to remove the sulfur and the other pollutants that are produced when coal is burned, and we have established a major research program to study the behavior and characteristics of pollutants and we have a special sulfur research center to coordinate that work at our State's laboratories and universities.

Our program to demonstrate clean coal technologies was begun more than 10 years ago. Right now in Illinois we have funded through State funds four what you could really call generations of fluidized-bed boiler technologies, for example.

Mr. Chairman, I know that you are aware of our kiingas coal gasification project, and we appreciate the role you have played in helping us obtain Federal funds for that project. We are also demonstrating flue gas desulfurization technologies, both for our largest State-owned powerplant and with a major Illinois utility.

And finally, when new technologies come off the drawing board and have been demonstrated and are commercially available, we have a low-interest loan program to promote their use in Illinois industries.

There is one additional fact about Illinois that I feel should be noted, and that is that today our emissions from Illinois utility powerplants are only half of what would be allowable under the Federal regulations. One important reason for that is that well over 90 percent of Illinois coal is cleaned before it is used.

I would also like to note——

The **Chairman**. Is that a matter of regulation or just practice?

Ms. **Moreland**. It is a matter of practice because the regulations do not recognize——

The **Chairman**. Thank you.

Ms. **Moreland** [continuing]. Sulfur reductions achieved by cleaning in that way.

The point that I am making with this preliminary material is that Illinois citizens have shown themselves to be willing to invest in cleaner air, to be willing to invest in clean-coal technologies, and we believe that cleaner air can be accomplished without economic dislocation, without loss of jobs, and without severe negative impacts on our State and other States in the Midwest.

That is where the Federal clean coal technology initiative was extremely important to us and why our Governor, James Thompson, has been a strong advocate of the Clean Coal Technology Program and why we have committed State funds to four clean coal technology demonstration projects that have been proposed. And those are described briefly in the written testimony that I submitted.

We appreciate the opportunity to comment on ways in which the Clean Coal Technology Program could enhance efforts to reduce acid rain and in that regard we believe that the committee should give serious consideration to the following issues:

The first one and the most important one is that clean coal technologies need time to develop. And if Congress elects to deal with acid rain issues by requiring arbitrary, large, and rapid emission reductions, then even the most promising technologies for control of sulfur and nitrous oxides and other pollutants will not be considered because of technical and regulatory risks.

Second, we believe very strongly that for actual reductions in emissions to occur, attention should be given to retrofit technologies which could potentially control the pollution from the older plants, the ones that were conducted prior to 1972, and which are not now generally required to install special pollution control equipment.

A third, and a closely related point and one that was made by Mr. Berger earlier, is that technologies for these older plants must be as cost-effective as possible. In Illinois we believe that significant reductions in sulfur oxides and nitrous oxides can be achieved by some of the advanced technologies that are now emerging, that have not been demonstrated, that promise moderate reductions at relatively low cost, such as the dry sorbent injection technologies. When developed, these systems can perhaps achieve reductions in sulfur emissions of 50 to 60 percent combined with reductions in nitrous oxide, and we believe that if these systems were successfully commercialized, they could contribute significantly to reductions in acid rain precursors.

Just as an example, if you installed those types of technologies, if they were successful, at the three Illinois utility plants with the highest emission levels, total sulfur emissions in the State of Illinois would be reduced by 34 percent. So the reductions that could be achieved at relatively less cost could be significant.

And finally, this Committee should consider actions that will accelerate clean coal technology development. Congress has already set aside $350 million in the Clean Coal Technology Reserve. This additional funding could support an expanded clean coal technology program. The resulting $750 million program would represent an important step in realizing the $5 billion cost-share program outlined in the report of the Special Envoys on Acid Rain, which the administration has endorsed.

Thank you very much for providing me with this time, and I would be happy to answer any questions you may have.

[The prepared statement of Ms. Moreland follows:]

Testimony of Terri Moreland
Manager, Coal Development Section
Illinois Department of Energy and Natural Resources

Senate Committee on Energy and Natural Resources
June 9, 1986
Washington, D.C.

Good morning. My name is Terri Moreland, and I am happy to be here today on behalf of the State of Illinois. Our state is extremely interested in the development of clean coal technologies. With 181 billion tons of coal underlying 60 to 70 percent of the state and an excellent transportation network to deliver our product, we have a strong stake in the development of cleaner, more efficient ways to use our state's most abundant natural resource.

Illinois has invested more than any other state in the research and development of clean coal technologies. Our programs include grants for basic and applied research, support for full-scale demonstration projects and low-interest loans for industrial coal conversions. To date, we have provided over $55 million for such activities. The Illinois coal development programs are based on public-private partnerships. Our state-supported projects represent nearly $400 million in investments by private industries, utilities, research organizations, universities and the federal government.

Governor Thompson has been an active proponent of a sustained, adequately-funded, Clean Coal Technology program at the federal level. Now that Congress has provided for the program and the President has agreed to it, we are optimistic about its future. We believe that it will be of great significance to our state and to all of the nation, if it is given time to work.

The Illinois Programs

Such a program has been working in Illinois for nearly a decade. We have focused our funding and our efforts specifically on finding ways to control the sulfur and other pollutants emitted when coal is burned. Illinois' technology demonstrations include four generations of atmospheric fluidized-bed boilers. Our KILnGAS coal gasification project represents a clean and efficient way to use coal for electric utility power generation. Mr. Chairman, you and this Committee have been supporters of the KILnGAS project and we thank you again for your encouragement. On another project, we are installing a highly advanced Chiyoda flue gas desulfurization system at our largest state-owned power plant, at the University of Illinois. Also, we have committed support to the demonstration of a regenerable flue gas desulfurization system at a major Illinois utility.

In addition to these demonstration projects, we have established a major research program to address the problems of sulfur in coal. We have created a special research center to coordinate sulfur research at Illinois' many universities and research organizations. This year, the State of Illinois provided nearly $3 million toward basic and applied research on sulfur-related issues.

Illinois also encourages the commercial installation of fluidized-bed boilers and other clean coal-burning systems by offering low-interest loans to assist Illinois manufacturers and industries in the conversion to Illinois coal.

Finally, Illinois and its citizens have taken action to promote air quality. Coal is a vital economic resource in our state and we are committed to protect and encourage its use. But it should be noted that the emissions of sulfur dioxide from utility power plants in our state are half of what they could be if Illinois simply sat back and complied with federal regulations. A significant portion of these reductions is due to the fact that over 90 percent of the coal mined in Illinois is cleaned before it is burned. It should also be noted that reductions in sulfur emissions resulting from coal cleaning are not recognized or credited under existing regulations.

The Clean Coal Technology Program

Illinois believes that the continued development of clean coal technologies is critical to realization of this nation's clean air goals as well as to the economic well-being of citizens in many states. The federal Clean Coal Technology program is a key to reconciling these often conflicting but equally important objectives. We applaud Congress and the Administration for the steps it has taken to establish this program, and we hope to play a role in it as it moves forward.

With the support of Governor Thompson, we have proposed four technology demonstration projects to be undertaken through the U.S. Department of Energy program. Three of these projects, co-sponsored by Energy and Environmental Resources Corporation, involve the demonstration of retrofit dry sorbent injection technology for the reduction of sulfur and nitrous oxide emissions from three common types of utility boilers. We believe that retrofit technologies are particularly important in resolving acid rain issues. I will address this point in greater detail in a moment. The fourth project that our state has pledged to support is a turbocharged, pressurized fluidized-bed boiler, to be located at a Wisconsin Electric Power Company utility generating station. We have committed the equivalent of $1 million dollars to that demonstration project for activities related to the clean use of Illinois coal.

Recommendations

The Committee has requested our comments on how the Clean Coal Technology program can meaningfully enhance efforts to reduce acid rain. The State of Illinois recommends that the following issues be considered in this regard:

*Clean coal technologies need time for demonstration. Much of the acid rain legislation introduced in Congress requires strict emission reductions within a limited time frame. If Congress elects to deal with acid rain issues by requiring arbitrary, rapid and large emission reductions, innovative technologies will not be considered because of the technical and regulatory risks involved. Our state encourages Congress to question any legislation that puts severe economic burdens on some states and inhibits the development of cleaner, more efficient and economical technologies.

*Consideration should be given to moderately efficient control technologies for retrofit applications, as well as those intended for new generating capacity. Under the provisions of the Clean Air Act, new utility power plants are required to install control technologies to achieve 90 percent removal of the sulfur dioxide emissions produced from high-sulfur coal, and 70 percent of those produced from low-sulfur coal. Because of these "New Source Performance Standards", sulfur emissions from new coal-fired power plants would not generally exceed even the most stringent limitations which have been proposed in recent acid rain bills. Demonstration projects now underway in Illinois and elsewhere, as well as projects proposed for demonstration through the Clean Coal Technology program, promise improvements in efficiency, operational characteristics and economic factors for new plants, while meeting the required emission reductions. We believe that such demonstration projects should be supported so that these improved technologies can be deployed in the next generation of coal-fired power plants.

The achievement of actual reductions in sulfur emissions, however -- a central goal of those concerned with acid rain effects -- will depend on the development of technologies that can be utilized at plants constructed prior to 1972, which are not subject to new source standards. In Illinois, pre-NSPS plants represent approximately 6,400 MW of electrical steam generating capacity out of a total of 21,500 MW. In addition, they represent approximately 18 million tons per year in Illinois coal sales.

We believe that emissions can be reduced by 50-60 percent from these older plants without the economic dislocation inherent in fuel switching and without the high cost associated with conventional pollution control equipment. We urge the Committee to recognize this large and diverse category of plants and to consider actions which will foster the development of economical retrofit technologies.

*Cost-effective pollution control systems should be encouraged. Several emerging technologies promise to achieve moderate emission reductions at relatively low costs. The continued development of such systems could be an important step in future emission reductions, while keeping investment in plant retrofit equipment at a reasonable level. For example, industries, several states and the federal government have already initiated the development and refinement of sorbent injection technologies to control both sulfur and nitrous oxides. These systems are suitable for sulfur reductions of 50 to 60 percent. In combination with coal cleaning, slightly higher reductions could be achieved.

If such systems were successfully commercialized, they could contribute significantly to the reduction of acid rain precursors. For example, if such systems were installed on the three Illinois coal-fired utility generating plants with the highest emission levels, a total reduction of 377,000 tons per year of sulfur dioxide emissions alone could result. The total amount of sulfur dioxide emitted from all Illinois coal-fired utilities would be reduced 34 percent. Based on data published by the

Electric Power Research Institute, we have calculated that the levelized cost per ton of sulfur dioxide removed would be less than 40 percent of that required for conventional flue gas desulfurization equipment, while removal rates would equal 67 percent of those obtained with conventional systems.

Illinois recommends that the Clean Coal Technology program address the importance of developing such systems as a cost-effective strategy for the control of acid rain precursors.

*The Committee should consider actions that will accelerate technology development. Congress has set aside an additional $350 million in funding in the Clean Coal Technology Reserve established last year. This additional funding could be used to accelerate the development of coal technologies, particularly those for retrofit applications. The resulting $750 million Clean Coal Technology program would represent an important step in the realization of the $5 billion, cost-shared technology demonstration program outlined in the report of the special envoys on acid rain, also known as the Lewis-Davis report.

On March 5th of this year, Governor Thompson urged the President to adopt the report's recommendation for an expanded technology demonstration program (attachment one). President Reagan endorsed the report on March 18th. The recommendation program would greatly encourage industry and government to work together for solutions to acid rain issues.

In Illinois, we know that public-private partnerships can work to accelerate the development of clean coal technologies. We urge the Committee to support measures which will maximize the benefits of these technologies for our nation.

STATE OF ILLINOIS
OFFICE OF THE GOVERNOR
SPRINGFIELD 62706

JAMES R THOMPSON
Governor

March 5, 1986

The Honorable Ronald Reagan
President
The White House
1600 Pennsylvania Avenue
Washington, D.C. 20050

Dear President Reagan:

I want to congratulate you on the progress that has been made in our nation's dialogue with the Canadian Government on transboundary acid rain. Your agreement with Prime Minister Mulroney to appoint special envoys to examine the acid rain issue has resulted in a better understanding in both countries, as demonstrated in the joint report of special envoys Drew Lewis and William Davis. I read with great interest the joint report, as any federal action concerning acid rain is of great interest to Illinois due to our large and economically critical coal deposits.

The primary focus in the report on the need to develop innovative control strategies, including clean coal technologies, is highly appropriate. I urge you to work with the Congress to allocate the needed resources to meet the goal of the five year demonstration program recommended in the report. I am willing to help in any way that will make this demonstration program a reality. Further, I endorse the recommendation to establish a panel to oversee the research demonstration program. Illinois would be very pleased to participate on that panel, and I offer my assistance.

I have long been a proponent of research into clean coal technologies, and have allocated significant state resources to coal research efforts in Illinois. A recent report of the Illinois Department of Energy and Natural Resources has found that the Illinois basin contains over 1,000 years worth of coal. Illinois has vigorously pursued research and demonstration programs aimed at the clean, economical use of Illinois coal. Through its research and demonstration program, the State provides funding and other support at eleven universities and research institutions. This effort has an annual budget of $2.25 million, not including private sector or federal contributions. Research is currently concentrated in the areas of coal characterization and advanced cleaning.

Through the Coal Development Fund, the State provides capital bond funding to projects which demonstrate new and innovative coal utilization technologies. To date, $40 million of state funds have been provided to projects demonstrating coal gasification, fluidized bed boilers, and advanced scrubber technologies.

This year the Illinois General Assembly approved, at my urging, a new program to provide low-interest loans to Illinois industries which convert to Illinois coal for their plants' power sources. New, more clean burning boilers are also eligible. The first year funding is $7.5 million for this five year $55 million program.

Illinois is making a substantial contribution to researching and developing clean coal technologies. I have also strongly supported federal clean coal programs, including the multi-year funding for the Clean Coal Technology Reserve Program which Congress authorized last year. This new program is aimed at demonstrations of innovative technologies which show that our nation's coal can be utilized in an environmentally acceptable and economical manner. The objectives of the program are similar to the recommendations made in the envoys' report. I applaud your recent decision to proceed this year with the Clean Coal Technology Program.

Illinois is willing to assist in any responsible acid rain control effort that recognizes the cost of controlling acid rain and avoids disproportionate economic impact on any one region or industry. The demonstration program recommended in the report is an excellent way to lay the foundation for acid rain control. As the Governor of a major industrial and large coal producing state, I appreciate the well reasoned approach by Drew Lewis and William Davis, and I look forward to assisting in the implementation of their recommendations.

Please feel free to call on me for assistance in this matter.

Sincerely,

James R. Thompson

James R. Thompson
GOVERNOR

JRT/lbc

The **Chairman**. Thank you very much.

I think each of the three of you on this panel in your statements has focused in different ways or in identical ways focused on one question: that is the pace at which we move forward. Each of you in one form or another has suggested that if we move forward urgently, if we move forward on very short timetables with respect to the application of technologies to clean up the flue gases that we may prejudge the selection of technologies to our detriment.

Do I read each of you correctly?

Mr. **Berger**. Yes.

Mr. **Greer**. Yes.

Ms. **Moreland**. Yes.

The **Chairman**. If that is a common thrust of your statement, what kind of a timetable should we be on?

Mr. Greer.

Mr. **Greer**. My understanding, Senator, is that we are still 3 to 5 years away. In many instances—

The **Chairman**. Of some understanding of the technology?

Mr. **Greer**. From commercial application of the clean coal technology.

The **Chairman**. Mr. Berger.

Mr. **Berger**. Mr. Chairman, 3 to 5 years with respect to proving out the emerging technologies. I will use an example which Administrator Thomas referenced, which is the limestone injection project we have underway at Edgewater. That alone is a 4-year demonstration program by the time we apply it to one 100-megawatt wall-fired unit, by the time we go through all the engineering exercise.

I do not think we are going to find too many new discoveries that are likely to be applied to deal with the acid precursors. Rather, the issue is, can we prove them out and apply them to the diversity of existing infrastructure that is out there, bearing in mind it is very diverse, different boiler types, and specific siting circumstances that will or will not permit the application of one technology over technology B.

So one, we have to prove the technology; but then, second, we have to prove it in a variety of settings. So it is a two-fold mission.

The **Chairman**. Ms. Moreland.

Ms. **Moreland**. I would agree that given time and incentives and the opportunity to develop technologies such as the sorbent injection technology, LIMB and the technologies related to it could be developed for commercial application within the next 5 years.

The **Chairman**. So would each of you then suggest that the Congress, in establishing an acid rain program, recognize and allow for that upfront development and proof time before requiring application?

Ms. **Moreland**. Certainly. And also I would recommend that the program would also help to advance and enhance technology development, if it could be flexible, if it could allow for flexible timeframes and incentives for installation of new technologies.

The **Chairman**. If I read the figures correctly, we are seeing the expansion of coal-fired electric production over the next 5- to 10-year period through the plant extension of existing plants. It is not simply the extension of existing nameplate capacity or even output. It is the expansion of total electrical generation, which some people charge is an obvious attempt to evade the restrictions on new plants by extending the life of old.

Do any of you see a problem, either economically or technologically, if indeed current policy or the uncertainty of policy forces the extension of the life of existing plants for the purpose of avoiding the strictures that would be applied to new?

Mr. Berger? It is a long question.

Mr. **Berger**. Our particular circumstance, though, is one in which we will not be adding additional coal-fire capacity over the next 20 years. So I guess we are into a life extension mode, if you will.

The **Chairman**. Even at the existing plants? The existing plants, even if they are extended, will not produce more electricity than they now produce?

Mr. **Berger**. There are no plans, Mr. Chairman, to what I would call repower an existing plant. That would be equivalent to pulling out an existing boiler and installing an atmospheric fluid bed boiler. We will have one additional coal-fired facility coming on line, perhaps, in the early nineties, the converted Zimmer plant near Cincinnati. That is another 1300 megawatts. That is it for coal.

The planning horizons, the forecasts filed by our investor-owned utilities, will indicate all the existing coal units continuing forward over the next 10 to 20 years.

The **Chairman**. Ms. Moreland?

Ms. **Moreland**. Illinois is in a similar position. I do not believe that there are plans right now for the construction of any new coal-fired facilities.

The **Chairman**. I am not talking about the construction of new plants. I am talking about the extension of the life of old plants and whether or not they expand their electricity production in the process of extending their life.

Ms. **Moreland**. Of course, if plants are modified under current regulations and that modification causes a cost of 50 percent of the cost of a new plant, my understanding is they are considered new sources of pollution.

The **Chairman**. But if they are less than 50 percent, they are not?

Ms. **Moreland**. If they are less than 50 percent, it is my understanding that they are not. I do not know particularly what kind of life extension could be applied to new plants that would not force them into that new-source category.

The **Chairman**. Mr. Greer?

Mr. **Greer**. Our situation is not unlike that of the others. We have no plans for new construction nor am I aware of any proposal to make plant modifications such as you described. I would think, as a regulator, that any strategy, to make such modification, would be scrutinized extremely closely and would have to be very cost-justified.

The **Chairman**. I will have some further questions to submit for response in writing, and other members of the committee may also have, by close of business on Thursday for submission of such questions. We would hope for prompt replies so that the replies may be included in the record.

Thank you all very much for your testimony here today.

That concludes the session of the committee. The committee will recess.

[Whereupon, at 12:56 p.m. the hearing was recessed, to reconvene Tuesday, June 10, 1986, at 10 a.m.]

APPENDIX I

RESPONSES TO ADDITIONAL COMMITTEE QUESTIONS FROM WITNESSES APPEARING JUNE 9, 1986

Department of Energy
Washington, DC 20585

July 18, 1986

Honorable James A. McClure
Chairman, Committee on Energy
and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

On June 9, 1986, Mary L. Walker, Assistant Secretary for Environment, Safety, and Health, and Donald L. Bauer, Acting Assistant Secretary for Fossil Energy, appeared before your Committee to discuss acid rain control and clean coal technology development.

Following that hearing, you submitted written questions for our response to supplement the record. Enclosed are the answers to those questions, which also have been sent directly to the Committee staff.

If you have any questions, please have your staff call Dottie Karsteter, Mike Gilmore or Cathy Hamilton on 252-4277. They will be happy to assist.

Sincerely,

Robert G. Rabben
Assistant General Counsel
for Legislation

Enclosures
- Set I (Joint Answers)
- Set II (Donald Bauer)
- Set III (Mary Walker)

SET I

POST-HEARING QUESTIONS AND ANSWERS

relating to the

JUNE 9, 1986, HEARING

before the

COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

WITNESSES: MARY L. WALKER
ASSISTANT SECRETARY FOR ENVIRONMENT, SAFETY, AND HEALTH

and

DONALD L. BAUER
ACTING ASSISTANT SECRETARY FOR FOSSIL ENERGY

DEPARTMENT OF ENERGY

QUESTIONS 1 THROUGH 10

QUESTIONS FROM CHAIRMAN MCCLURE

Question 1: Each of you, as representatives of the Administration, has emphasized that the President fully endorses the January 1986 Joint Envoys' Report on Acid Rain. However, I am unclear what that endorsement actually represents.

a: For example, are you saying that the Joint Envoys' Report is the Administration's, or more importantly the United States', policy on the need for acid rain mitigation, including schedules for its control?

Answer: The Administration's policy on the need for additional acid rain control is that we are uncertain whether and what controls are needed and when they might be needed. That position is stated in the middle paragraph on page 25 of the Envoys' Report (US printing). The rationale for the position can be found on pp. 16-19, where effects are discussed, and pp. 20-21 where the effectiveness of current emission control programs are discussed.

It is also Administration policy to continue and, as warranted, expand research into the causes and effects of acid deposition and on the development of more efficient, less expensive control technologies. Those efforts are intended to (1) identify sources and quantify levels of emissions contributing to acid deposition; (2) monitor impacts on geographical regions identified as "sensitive" or "at risk"; (3) develop dose-response data bases and formulate and prepare economic assessments; and (4) develop additional control technologies that can contain acid-related damage, if additional controls are needed.

It is not Administration policy that any particular additional control strategy will be needed by any particular time. As has been stated on several occasions, when fundamental scientific uncertainties are reduced, this Administration will craft and support an appropriate set of measures to solve the acid rain problem. There are a variety of possibilities, including continuation of current regulations and authorities, that might be found to be justifiable. At present, there is insufficient information to choose between them.

b: Does the President's endorsement of the Joint Envoys' Report mean the Administration supports a 5-year, $5 billion clean coal technology demonstration program? Would each of you comment.

Answer: The Administration fully endorses the Envoys' Report. There are two considerations which could affect the realization of the full $5 billion demonstration program as recommended in the Report: (1) the magnitude of industry's response and, (2) the quality of that response. As stated in testimony, we will be in a better position to evaluate the potential for expansion of the Clean Coal Technology Program after industry responses have been evaluated and awards have been made and those projects are assessed in conjunction with other Federal, State and private sector efforts.

Question 2: The Envoys' Report presents both the United States' and the Canadian positions on the causes of acid rain and the need for its control. In some instances the positions are different. For example, it is the Canadian perception that, unless additional measures (such as the Canadian reduction program) are implemented, the total emission of sulfur oxides affecting Canada will increase. Does the U.S. endorsement of the report mean that the Administration agrees with the Canadian position?

Answer: No. Differences in the perception of the problem led to separate statements. For example, Canada states, on page 29 of the US printing of the Envoys' Report, that "damaging acidification of many ecosystems will continue even with some decreases in total emissions--". In contrast, we state, on page 17, that "-- it cannot be predicted what future acidification, if any, would occur if current levels of deposition were to continue" (emphasis added). That is a crucial difference. Indeed, it characterizes the difference in perspective between proponents of additional controls in the immediate future and proponents of adequate research before determining if any further steps are needed.

Question 3: The Special Envoys' Report recommends establishment of a panel headed by a senior U.S. Cabinet official to oversee the research demonstration program and select the projects to be co-funded by the Federal government.

a: Is this panel going to be established? If so, who is the senior U.S. Cabinet official?

Answer: The senior U.S. Cabinet official will be the Secretary of Energy or his designee. The panel is expected to include representatives from the Departments of Commerce, Energy, Interior, and State, the Environmental Protection Agency and Office of Management and Budget. The actual functions that will be performed by the panel, consistent with existing U.S. authorities, are now being determined.

b: If not, what specific interagency mechanism will be established to implement the Special Envoys' Report?

Answer: The panel will be established.

c: With regard to the DOE Clean Coal Demonstration Program, will DOE make the final selection of proposals? What is going to be the role of the "Panel" referred to in the Special Envoys' Report? Or of OMB?

Answer: The panel of the Special Envoys' Report will not participate in the final selection of proposals for the Clean Coal Demonstration Program being carried out in response to P.L. 99-190. The panel will evaluate the results of the Clean Coal Technology Program solicitation under P.L. 99-190, including the mandated reports on DOE follow-up activities.

d: How could the goals of clean coal technology development and acid rain control be better coordinated between EPA and DOE?

Answer: Considerable coordination between DOE and EPA on clean coal technology development and acid rain control has been taking place for a long time. DOE and EPA are both active on the

Interagency Task Force for Acid Precipitation, the acid rain research coordinating body for Federal agencies. EPA is invited to and does participate in DOE conferences and contractor reviews dealing with research on clean coal technologies, primarily flue gas cleanup and coal preparation systems being conducted by DOE and its contractors. Likewise, DOE is invited to and does participate in EPA conferences and contractor reviews dealing with research on new environmental technologies applicable to coal technologies. Informal coordination meetings between representatives of the two agencies, at every technical and management level, occur routinely. In addition, EPA is participating as an environmental advisor and technical evaluator to DOE on the Clean Coal Technology Program, which is currently in the proposal evaluation stage.

Continued coordination will better ensure that the goals of our respective programs will be met.

Question 4: As Chairman of the Authorization Committee for the Clean Coal Technology program and the Interagency Taskforce on Acid Rain Research, I request that each of you keep this Committee fully and completely informed of progress in these areas.

Answer: Of course. The Assistant Secretary for Fossil Energy and the Assistant Secretary for Environment, Safety and Health will handle such communication between DOE and the Committee in their respective areas.

Question 5a: In your opinion, what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the extension of the life of existing facilities rather than their retirement and replacement with new facilities?

Answer: That depends on what the "new acid rain regulatory requirements" might be. Since the Administration is not yet ready to make a recommendation on the issue (see Q12/A12), it is impossible to estimate how industry will be affected. The Administration opposes at this time proposals, such as HR4567, for added emission reductions. However, some speculation as to industry response to further reductions is possible.

Life extension is driven by economic realities, and is likely to occur whether or not additional controls are required. That is because plant replacement is much more expensive than refurbishment, with or without retrofit controls.

In marginal cases, the cost of any retrofit requirement could affect a decision on whether to refurbish or retire, or induce retirement or refurbishment earlier than planned. But the direction of such influence isn't clear. On one hand, the cost of retrofit could induce refurbishment to help recapture the investment. On the other hand, retrofit difficulties, especially if added control equipment would be needed, could induce earlier retirement. This, in turn, could accelerate planning and construction of replacement capacity.

b: Under what circumstances will life-extension result in reduced atmospheric emissions?

Answer: Although not directly related, life extension might result in emission reductions if new clean coal technologies are utilized.

c: In your judgments, should utilities be permitted to shift to imported oil to comply with acid rain controls?

Answer: The Administration favors allowing market considerations to allocate fuel use. Within this general policy, we favor the use of domestic fuels, especially the more abundant domestic fuels such as coal, within the framework of regulations to assure appropriate environmental and human health protection.

As the Secretary has testified, we look askance at proposals such as H.R. 4567 which could alter market forces to favor imported oil over coal. It is unlikely that we would propose restrictions on market choices unless the result of not doing so would substantially compromise energy security.

Question 6: There has been considerable mention of the need to place emphasis on the development of clean coal technologies with retrofit application.

The Special Envoys' Report also emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

a: In your judgments, does the DOE Clean Coal Technology Program adequately reflect this need? Or does the program place too much priority on technologies applicable to new construction?

Answer: Several technologies under investigation in the clean coal programs have potential application to both new and existing plants. Some technologies, like fluidized bed, are more amenable to repowering than added retrofit equipment. Either choice is still more economical than plant retirement/replacement in most cases. Therefore, we believe that the present program serves both new facilities and retrofit applications appropriately. The Clean Coal Technology Program is open to both new and retrofit applications.

b: Conversely, do these statements in the Envoys' Report suggest that it is the Administration's judgment that the DOE Clean Coal Technology Program should be limited to retrofit technologies?

Answer: No. The Administration has been guided by the Congressional direction that the Clean Coal Technology Program should be open to both new and retrofit applications. This guidance is reflected in the Program Opportunity Notice (PON) issued on February 17, 1986. Proposals submitted to DOE in response to the PON will be evaluated in accordance with the criteria specified therein.

c: Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control? Should they be?

Answer: According to Congressional guidance, the solicitation for the Clean Coal Technology Program was open to all clean coal technologies, all U.S. mined coals, and all market applications. It is not possible at this time to determine the extent to which projects selected under CCT are likely to be appropriate for acid rain control until selections are announced on or before August 1, 1986.

QUESTIONS FROM THE MAJORITY

Question 7:	Are the technologies being developed by the DOE Clean Coal Technology Program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?
Answer:	Based upon the information provided by the public abstracts, it appears that many of the clean coal technologies offer the potential for economic improvements over the technologies they are proposed to replace. As a result, these technologies will likely be utilized for new and retrofit applications (a part of life extension), even under current regulatory requirements. However, there are some clean coal technologies for retrofit applications that are likely to be used only where new regulations or legislation call for pollution controls more stringent than those currently in existence. For these technologies, significant market penetration may be dependent upon new regulatory requirements.

Question 8:	What is the national average cost of FGD retrofit per kilowatt? And, what would be the aggregate cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements? What would be the differential cost between implementation of the above two options?
Answer:	The cost to retrofit a power plant with an FGD is highly variable from plant to plant. Therefore, there is a wide range of estimates. For example, the Electric Power Research Insitute (EPRI) has published a SO_2 and NO_x Retrofit Control Technologies Handbook (EPRI CS-4277-SR) which contains their best estimates. Based upon the EPRI data the range of average capital cost could be estimated at \$150-\$350/KW. In addition to the capital costs of these retrofits there would be additional operating maintenance and fuel costs. The range of total costs could be \$400-\$1000/ton of SO_2 removed. These ranges are stated in constant 1985 dollar terms. If one assumes the population of plants to which retrofits would be applied is approximately 50,000MW, the total capital cost could be \$7-18 billion, (constant 1985 dollars) with an average cost-effectiveness of \$400-\$1000/ton of SO_2 removed. If the requirement was for specific emissions performance, the direct cost could be substantially lower. How much lower depends upon the control strategies employed and some of those strategies, particularly coal switching, could have additional indirect costs due to job displacement and other social and infrastructure cost impacts. The cost projection is also highly dependent upon whether one bases the estimate upon only currently available technologies or whether improved clean coal technologies which will be reaching

the commercial demonstration stage can be anticipated as likely control options.

Again referring to the EPRI Handbook data, it appears reasonable to assume that a 25-50% reduction in the average cost range might be achievable depending upon the level of emissions performance required and the extent to which advanced clean coal technologies are included as an alternative. Some of the more cost-effective approaches may not be applicable if very high levels of emission removal were required. Similarly some of the more cost-effective approaches will not have reached commercial status until the 1990's.

Question 9:	What, in your judgment, are the estimated costs of implementing proposed acid rain legislation? Would you indicate the sources of such cost estimates and whether you agree, or disagree, with such analysis?
Answer:	There are numerous alternative forms, degrees and schedules for potential acid rain controls, including continuation of existing controls. Most Congressional proposals call for emission reductions of 10 million ton per year (MTY) SO_2. Cost estimates for such programs generally fall in the range of \$3-7 billion per year for years close to the compliance deadline. They rise steeply in the years just before, and they decline slowly in the decades after. The present value of such a stream of costs lies in the range of \$25-70 billion, depending on many factors including whether the most economical compliance means can be chosen by industry. These estimates are based on analyses done by the Office of Technology Analysis, Argonne National Laboratories, ICF, Inc., and Temple, Barker and Sloane.

We hesitate to endorse or criticize any particular analysis, for all such analyses are only the implications derived from a set of assumptions concerning future conditions and behavior, and such assumptions are always selected from within an uncertainty range.

In 1982, DOE performed a comparative analysis of various emission control schemes.1/ Its methodology and general conclusions are still relevant. A copy is enclosed.

1/ DOE/PE-0042: Costs to Reduce Sulfur Dioxide Emissions, March 1982.

DOE/PE-0042

Costs To Reduce Sulfur Dioxide Emissions

March 1982

U.S. Department of Energy
Office of Policy, Planning,
and Analysis
Divisions of Environment and
Fossil Energy
Washington D.C. 20585

THE SECRETARY OF ENERGY
WASHINGTON D C 20585

May 5, 1982

Honorable Robert C. Byrd
United States Senate
Washington, D.C. 20510

Dear Senator Byrd:

The debate on acid rain and the associated control measures is a matter of significant concern to this country's energy consumers and producers. I strongly believe that consideration of the matter must strike an appropriate balance between our desire for environmental protection and the cost of control measures to the Nation.

I should like to share with you some important information on the prospective costs for the most frequently suggested control measures. I am, therefore, enclosing a new Department report on "Costs to Reduce Sulfur Dioxide Emissions." This report examines the technical means to reduce sulfur dioxide emissions and estimates the costs necessary to achieve various control levels. Some important findings in the report are:

- The Nation would incur an annual $3.6 billion cost to achieve the suggested annual reduction of 10 million tons of sulfur dioxide emissions. Over a 30 year period, these expenditures would exceed $100 billion, excluding the effects of inflation.
- The Coal study estimates that the employment of at least 5,000 coal miners and the production of 20 million tons of coal would be lost for each one million tons of sulfur dioxide reduction acheived through fuel switching.
- The use of flue gas desulfurization units would require electric utilities to invest $1 to $2 billion for each one million tons of sulfur dioxide reduction.

These are very imposing costs to be borne by energy consumers. We must be sure that the proposed emission controls will truly mitigate the effects of acid rainfall before subjecting our energy industries and energy consumers to such expenditures. Because our current scientific understanding does not explain how the effects of acid rainfall can be mitigated, I believe we must act with caution until our knowledge is improved.

I hope that our study is useful to you and your constitutents.

Sincerely,

James B. Edwards
James B. Edwards

Enclosure

BACKGROUND

Despite the widespread attention the acid rain issue has received from the scientific community and in public and political forums, basic questions concerning the causes and effects of acid precipitation remain unanswered. Inadequately explained at present are the origins, transformation processes, and long-range transport patterns of chemical species that can cause precipitation to be acidic. In addition, our understanding of the impacts of acidic precipitation on terrestrial and aquatic ecosystems is only beginning to be developed. Nonetheless, observations of rainfall with greater than expected levels of acidity and of lakes with high acidic content have prompted calls for action, particularly from the northeastern U.S. and southeastern Canada.

It appears that the target of those calling for immediate action are coal-fired electric powerplants. The main rationale for this targeting appears to be the fact that these powerplants are a major source of sulfur dioxide emissions in the United States and that winds generally blow from west to east. Most of the existing coal-fired powerplants are located in the Midwest and the likely targets are those burning medium or high sulfur coals. Almost all of these powerplants were built prior to regulations requiring installation of sulfur dioxide control equipment on all new powerplants.

A Note on Format:

Throughout the report, the right-hand page displays a chart or series of important concepts, accompanied by supporting text on the left-hand page. This format is designed to facilitate use of the document as a briefing package.

BACKGROUND

- IT IS GENERALLY RECOGNIZED THAT THERE ARE MAJOR UNCERTAINTIES AS TO THE CAUSE AND EFFECTS OF ACIDIC PRECIPITATION.

- NEVERTHELESS, CONCERN OVER POSSIBLE DETRIMENTAL EFFECTS HAS CAUSED GROUPS WITHIN THE UNITED STATES, AS WELL AS THE CANADIAN GOVERNMENT, TO CALL FOR A REDUCTION IN GROSS (OVERALL) EMISSION LEVELS OF SULFUR AND NITROGEN OXIDES.

- THE FOCUS OF THOSE CALLING FOR IMMEDIATE CONTROLS HAS BEEN COAL-FIRED ELECTRIC POWERPLANTS.

  - PRIMARILY LOCATED IN THE MIDWEST
  - CURRENTLY BURNING MODERATELY HIGH OR HIGH SULFUR COALS
  - BUILT PRIOR TO REGULATIONS REQUIRING THE USE OF SULFUR OXIDE CONTROL EQUIPMENT (SCRUBBERS)

PURPOSE OF BRIEFING

Central to the resolution of the acid rain issue are debates about the costs and benefits of controlling man-made emissions of chemicals that may cause acid rain. In this briefing, we shall examine the position of those who are calling for immediate action and implicating coal-fired powerplants as the cause of the problem. We shall present the costs of controlling sulfur dioxide emissions using alternative control methods available today. We shall not, however, attempt to calculate the benefits of reducing these emissions since insufficient information is available to provide even a rough estimate.

This presentation will proceed in two steps. First, costs will be presented as obtained through straightforward calculations based upon simplifying but realistic assumptions. The advantages of these straightforward calculations is that they provide intuitive insight into the factors that drive the overall costs.[1] Next, we shall summarize the costs of sulfur dioxide control obtained through several large-scale analyses and compare these results with those obtained through our straightforward methods.

It is important to recognize that this briefing does not present the costs of acid rain control, but rather the costs of measures being proposed by advocates of immediate control. From the scientific and technical information available to us, we are not able to relate sulfur dioxide control levels to benefits associated with alleviating acidic precipitation.

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[1] Descriptions of the algorithms used are detailed in the Appendix.

PURPOSE OF BRIEFING

- TO PRESENT AND REVIEW COSTS OF REDUCING THE LEVELS OF SULFUR OXIDES FROM UTILITY POWERPLANTS CURRENTLY BURNING COAL.
  - CONSTITUTES A PRESENTATION OF THE COST HALF OF THE COST/BENEFIT EQUATION
- TO PROVIDE INSIGHT ON THE FACTORS WHICH CONTROL THESE COSTS.
  - WILL COMPARE RESULTS OBTAINED THROUGH STRAIGHTFORWARD CALCULATIONS WITH THOSE OBTAINED FROM ECONOMETRIC MODELS OF THE UTILITY SECTOR

SCOPE OF ANALYSIS

This briefing is limited to examining the costs of controlling sulfur dioxide emissions beyond the levels required by the Clean Air Act. The primary reason for imposing such additional controls would be to address the acid precipitation issue, if the benefits of such controls were found to be commensurate with the costs. In the context of acid precipitation, it is important to recognize that sulfur dioxide emissions from coal-fired powerplants may not be the only precursor pollutant of concern. There exist other sources of atmbspheric sulfates, and other pollutants e.g., oxidants, may regulate the rate of acid formation. Also, nitrogen dioxide emissions form acidic compounds in the atmosphere.

The analyses that underlie the costs presented in this briefing are limited to the utility sector, in particular, to coal-fired utilities. These utilities are a major source of sulfur dioxide emissions in the United States. In addition, utility powerplants are fairly large. Therefore, we generally expect that control of such sources will incur lower costs per ton of reduction than, for example, control of industrial boilers. It appears that these are the reasons why advocates of immediate controls have focused their efforts on this sector. Therefore, by looking at utilities, we can obtain an appreciation of the cost implications of moving towards early control and accepting their assumption that gross regional emission reductions are the answer.

Finally, to be practical, we shall consider only currently available control methods. There are alternative control technologies in the R&D pipeline. However, we expect none of them to be available for widespread commercial use for at least five years and possibly much longer. Therefore, no decision on controlling sulfur dioxide emissions should be predicated on obtaining a low-cost technological "fix."

SCOPE OF ANALYSIS

- LIMITED TO SO_2 CONTROL
    - OPTIMISTIC ASSUMPTION THAT SO_2 IS THE ONLY PRECURSOR POLLUTANT AT ISSUE
    - OTHER POLLUTANTS. SUCH AS NO_x. ARE KNOWN TO FORM ACIDIC COMPOUNDS IN THE ATMOSPHERE, THUS. THIS ANALYSIS DOES NOT PRESENT TOTAL POTENTIAL CONTROL COSTS
- LIMITED TO THE UTILITY SECTOR
    - MAJOR SOURCE OF SO_2 EMISSIONS IN THE U.S.
    - EXPECT CONTROL COSTS TO BE LOWEST IN THIS SECTOR IF GROSS EMISSION REDUCTIONS ARE THE ANSWER.
- LIMITED TO AVAILABLE METHODS
    - COAL SWITCHING
    - FLUE GAS DESULFURIZATION
    - COAL CLEANING
- IT IS UNLIKELY THAT OTHER TECHNOLOGIES NOW IN THE R&D PIPELINE WILL BE AVAILABLE FOR WIDESPREAD USE FOR AT LEAST FIVE YEARS.

APPROACH

The analysis reported in this briefing consists of two phases. First, the results of straightforward calculations will be presented. This will be followed by a review and comparison of contractor studies based upon more complicated methodologies. We are able to use a simplified calculation scheme because the dominant factors which drive the costs of each of the control methods can be identified and simplified assumptions can be made. These assumptions are realistic as long as we recognize that the resultant costs apply "on the average" and are willing to accept a range of costs rather than a single number. The advantage of the straightforward calculations is that the assumptions that underlie them are clear. If there is a disagreement with the costs presented, a rational discussion centered on the underlying assumptions can take place.

One of the assumptions that drives this straightforward analysis is that each of the three control methods examined is most cost-effective when applied to higher sulfur coals. "Cost-effective" means the lowest costs per ton of sulfur dioxide controlled. This assumption is intuitively obvious once the technical aspects of each of the control methods are examined. In addition, this assumption has been verified by a number of more complicated analyses.

Accepting this assumption, we have examined the cost of each of the three control methods when applied to all coals that have a sulfur content of greater than three percent and to all coals that have sulfur content greater than two percent. In both cases, we examined only coals used by utilities in the contiguous 48 states for electricity generation.

Because we are deriving costs for the more cost-effective opportunities to reduce overall sulfur emissions, it is important to recognize that these costs represent the minimum costs that can be anticipated based upon the performance of currently available control technologies. Such low costs may not be achievable using regulatory approaches. This will be discussed at greater length later in the briefing.

APPROACH

I. STRAIGHTFORWARD CALCULATIONS

- PROVIDES INSIGHT INTO UNDERLYING COSTS
- BASED UPON ASSUMPTION THAT EACH OF THE CONTROL METHODS IS MOST COST-EFFECTIVE WHEN APPLIED TO HIGHER SULFUR COALS
  - THIS ASSUMPTION HAS BEEN VERIFIED IN A LARGE NUMBER OF ECONOMETRIC STUDIES OF ENVIRONMENTAL CONTROL OPTIONS
- COST ESTIMATES ARE PROVIDED FOR TWO CASES:
  - CONTROLS ON ALL COALS GREATER THAN 3 PERCENT SULFUR
  - CONTROLS ON ALL COALS GREATER THAN 2 PERCENT SULFUR
- NOT A REGULATORY ANALYSIS BUT RATHER AN ANALYSIS OF MINIMUM COSTS BASED ON TECHNICAL LIMITATIONS
  - CRAFTING A REGULATORY STRATEGY TO ACHIEVE THE RESULTS SHOWN MAY NOT BE POSSIBLE

II. REVIEW OF AND COMPARISON WITH MODEL-BASED ANALYSIS

- BASED UPON POTENTIAL REGULATORY STRATEGIES
- PROVIDES INSIGHT INTO DISECONOMIES OF SCALE

ESTIMATE OF SULFUR AND NITROGEN DIOXIDE EMISSIONS

This chart is presented to illustrate a few key points relevant to any analysis associated with controlling sulfur dioxide emissions beyond currently mandated levels.

First, if alleviating acid precipitation is the driving factor, it is important to note that nitrogen oxides can also contribute to precipitation acidity. From both a global and U.S. perspective, nitrogen oxide emission levels are comparable to those of sulfur dioxide. In fact, a third to one-half of the measured acidity in the northeastern United States and southeastern Canada has been associated with nitrates. Although nitrogen oxides appear to play an important role in acid precipitation, an analysis of the costs associated with nitrogen oxide control is beyond the scope of this report.

Looking at just the sulfur dioxide column, it is evident that natural sources of sulfur dioxide are at least as important as manmade sources if we take a world-wide inventory. Comparing the global and U.S. totals, global emissions are at least 15 times greater than those of the United States. This fact is raised to emphasize the possibility that global emissions could reduce the effectiveness of any emission control program instituted in the United States. This, however, is but one of many uncertainties associated with understanding the benefits, if any, of reducing sulfur dioxide emission levels beyond those levels already required to protect human health and welfare.

Focusing only on the United States, it can be seen that coal-fired electric powerplants account for almost 60 percent of all U.S. manmade emissions of sulfur dioxide: 17 million tons of the approximately 30 million tons annually emitted in the United States.

Finally, it is important to recognize that the sources of emissions within the United States are not evenly distributed across the country, but rather are most prevalent in those states which have historically maintained a strong dependence upon coal. For example, coal-fired electric powerplants in ten states emitted more than two-thirds (or 12 million tons per year) of all sulfur dioxide emissions produced by coal electric powerplants within the United States.

Estimate of SO_2 and NO_x Emissions[1]
(Millions of Short Tons Per Year)

Region/Source	SO_2	NO_x
Global		
Natural	300-500	50-750
Manmade (1976)	230	50-60
Total	530-730	100-810
USA (1978)		
Coal Powerplants	17	5
Other Manmade	13	17
Total	30	22
10 States[2] (1978)		
Coal Powerplants	12	2.6
Other Manmade	6	1.4
Total	18	4

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[1] References for all charts are listed in the Appendix.

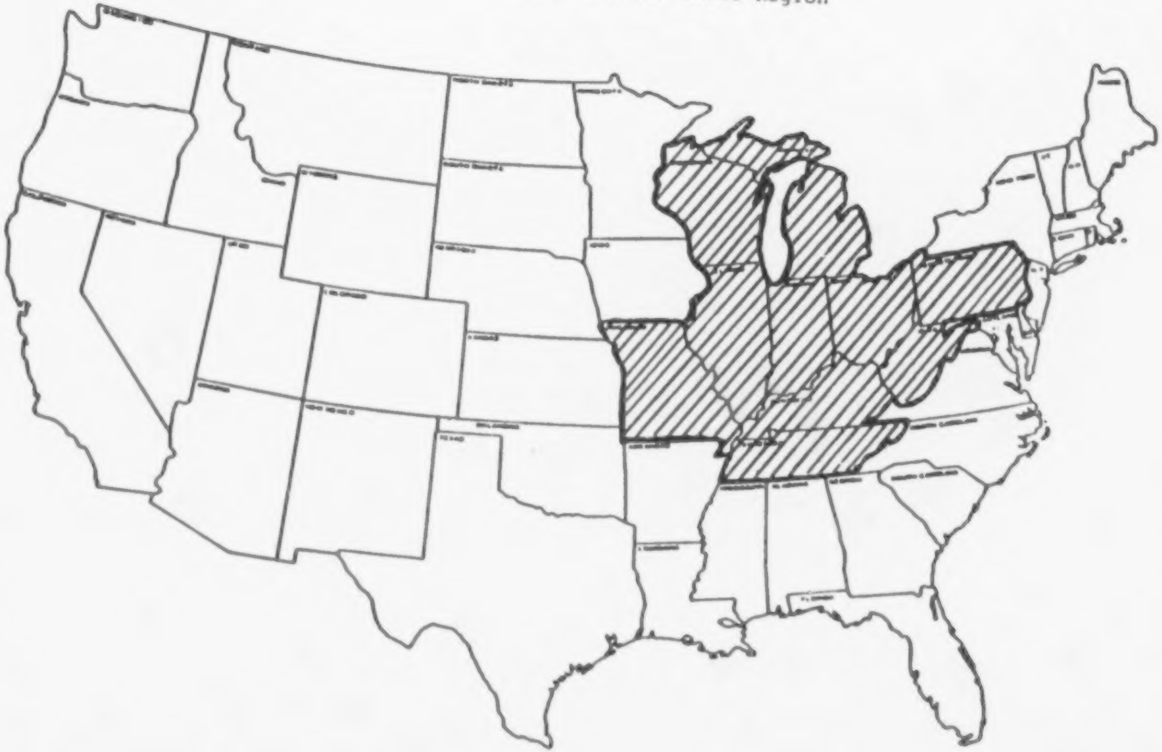
[2] See map on page 13.

MAP OF THE TEN STATE REGION

This map shows the location of the ten states mentioned on the previous slide. These states are contiguous and primarily located in the Midwest. In this region, the coal industry mines nearly all of the high sulfur coal produced in this country. For this reason, it is not unreasonable to find that these ten states generate approximately two-thirds of the national emissions of sulfur dioxide.

From the perspective of cost-effective control of overall sulfur dioxide emissions, these ten states play an even more dominant role. For example, in the minimum cost approach followed in our simple analysis, only utilities burning high sulfur coals (either greater than two percent or greater than three percent) will be affected. Almost all of these utilities are located in this ten state region. This is qualitatively shown in the next chart.

Map of the Ten State Region



DISTRIBUTION OF HIGH SULFUR COAL BURNING UTILITIES

This chart shows the amount of coal (in millions of tons) annually consumed by utilities in 1980. In all, utilities consumed approximately 590 million tons of coal. From this total, approximately 200 million tons had a sulfur content of greater than two percent, of which 100 million tons had a sulfur content of greater than three percent. However, more than 80 percent of coals used by utilities with a sulfur content of greater than two percent was consumed in the same 10 state region shown on the preceding map.

The implications of this distribution are that the cost of any attempt to further reduce sulfur oxide emissions will be almost completely borne by just ten states. For example, between 83 and 92 percent of the costs that we shall present would be borne by these states if a national "minimum cost" strategy were implemented.

Distribution of High Sulfur Coal Burning Utilities
[In Million Tons of Coal Annually Consumed]

REGION / COAL TYPE	10 STATES	48 STATES
Greater Than 3% S	87 (92%)	95
Greater Than 2% S	163 (83%)	197
All Coals Consumed by Utilities		594

COST CALCULATIONS

Page 17 shows the key input variables for the straightforward calculation scheme used in this analysis. Using information on the sulfur content of coals currently used by powerplants, we are able to calculate the average sulfur content for each of the two coal categories for which we will calculate control costs.

The key cost factors for coal switching, flue gas desulfurization, and coal cleaning are shown on the lower portion of the chart. Note that the cost factors for coal switching include not just the direct costs associated with purchasing more expensive coal and upgrading equipment but also the factor (miner productivity) that drives an indirect cost associated with displacing coal tonnage and therefore coal miners from their current jobs. The cost factors for flue gas desulfurization include the energy penalty associated with operating scrubber equipment, but do not include the costs of spare scrubber modules installed to ensure system reliability. The cost factor for coal cleaning assumes that capital costs associated with increasing coal production capacity as well as costs for transporting the coal are included in the higher purchase price.

Each of these input variables, with references where appropriate, and the actual calculations are explained in the Appendix to this briefing. It is merely a matter of simple arithmetic to check our calculations or to repeat them with different values for the cost factors.

COST CALCULATIONS: INPUT VARIABLES

Weighted Average Sulfur Content:[1]

All coals greater than 3 percent sulfur: 3.6 percent
All coals greater than 2 percent sulfur: 3.1 percent

Cost Factors:[2]

- Coal Switching: Switch to 1 percent sulfur coal

  Additional Coal Costs: $6 to $12 per ton--greater than 3 percent sulfur coal
  $4 to $10 ton--between 2 and 3 percent sulfur coal

  Capital Costs: $21 to $50 per kw capacity--upgrading equipment
  Miner Productivity: 9 tons of coal per man/day for deep-mined coal
  28 tons of coal per man/day for surface-mined coal

- Flue Gas Desulfurization: 85 percent removal

  Capital Costs: $140 to $250 per kw capacity
  O&M Costs: 3 to 6 mills per kwh

- Coal Cleaning: 20 percent removal

  Additional Coal Costs: $3 to $5 per ton

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[1] See Appendix pages 3-4 for calculations.

[2] See Appendix pages 5-10 for calculations.

SUMMARY OF CALCULATIONS

The results of our straightforward analysis are shown on this chart. We have chosen to report costs in terms of 1980 dollars per million tons of sulfur dioxide annually removed. A million tons represents approximately three percent of total U.S. sulfur dioxide emissions and between five and six percent of the emissions emanating from the ten state region we discussed earlier.

The second column shows the additional operating costs in millions of dollars per year associated with each control method. These costs represent funds that would be expended during each year that the control method would be in effect. For coal switching and coal-cleaning, these costs would be incurred in purchasing higher priced coal. For flue gas desulfurization, the amount shown represents the annual costs associated with operating and maintaining a wet scrubber. These costs are shown in 1980 dollars; actual funds expended would be larger due to inflation, which is not explicitly considered in this analysis.

The third column provides the capital costs in billions of 1980 dollars. These costs are one-time expenditures and represent costs that electric utilities would incur to build scrubbing facilities or to update their equipment to handle low sulfur coal.

(continued)

Summary of Calculations
(Per Million Tons of SO_2 Removed Per Year)

	Coal Type (Greater Than)	O&M Costs ($ Million/Year)	Capital Costs ($ Billion)
Coal Switching	3% S Coal	$120 to 240	$0.17 to 0.41
	2% S Coal	$130 to 280	$0.21 to 0.50
Flue Gas Desulfurization	3% S Coal	$110 to 220	$1.0 to 1.7
	2% S Coal	$130 to 250	$1.1 to 2.0
Coal Cleaning	3% S Coal	$220 to 370	NA
	2% S Coal	$260 to 420	NA

SUMMARY OF CALCULATIONS (continued)

Since each of these control methods involves a different combination of annual operating costs and one-time capital costs, it is difficult to compare one with another or with the other possible investment opportunities for these funds. For these reasons, annual and capital costs are often aggregated into a single number. There are two basic ways to do this: annual costs can be capitalized or capital costs can be annualized. In the former method, a quantity known as the "present value" is obtained which represents an equivalent lump sum (one-time) payment adequate to cover both capital and annual costs. In the latter method, a "total annualized cost" is obtained which represents an apportionment of the capital costs into annual payments. For those not familiar with these two methods, a more detailed description of each is included in the Appendix. The present value and total annualized costs of each of the three control methods are shown in the fourth and fifth columns of this chart.

Examining the present value column, our calculations indicate that a decision to reduce sulfur dioxide emissions by one million tons per year for a significant number of years (30 years in our example) has a cost with a present value between $2 and $6 billion. This large range is due in part to cost differences between the various control methods. The factor that dominates the spread in the reported cost range, however is the broad range of values used for each input variable. This was done purposely to emphasize real variations among actual electric utilities. These costs should be interpreted as minimum cost estimates since they are based upon technology limitations and do not reflect economic inefficiencies associated with implementing a specific regulatory approach.

If we consider a small reduction increment of no more than one or two million tons per year of sulfur dioxide emissions, we estimate that the present value of the "minimum cost" approach could be as low as $2 billion per million tons annually removed. The only way to achieve this "minimum cost estimate" would be to devise a regulation that looked at the entire utility sector and caused only those utilities with the lowest cost opportunities to reduce sulfur emissions to do so in the most cost-effective manner. The actual cost of real regulations could be considerably greater.

As higher reduction increments (e.g., 5 million tons per year) are sought, the average cost per million tons removed increases considerably, approaching the upper bounds of the ranges shown in the chart. This phenomenon of "diseconomies of scale" can be qualitatively explained as resulting when "easy opportunities" for applying each control method are used up. More difficult opportunities must then be employed on utility powerplants that require more expensive scrubbers or on plants that use expensive-to-clean or difficult-to-displace coal. In addition, increased demand for low sulfur coal would cause the price of all low sulfur coal supplies to increase.

Summary of Calculations
(Per Million Tons of SO_2 Removed Per Year)

	Coal Type (Greater Than)	O&M Costs ($ Million/Year)	Capital Costs ($ Billion)	Annualized Cost 1/ ($ Million/Year)	Present Value 1/ 2/ ($ Billion)
Coal Switching	3% S Coal	$120 to 240	$0.17 to 0.41	$130 to 270	$2.0 to 4.1
	2% S Coal	$130 to 280	$0.21 to 0.50	$140 to 310	$2.2 to 4.8
Flue Gas Desulfurization	3% S Coal	$110 to 220	$1.0 to 1.7	$170 to 330	$2.7 to 5.1
	2% S Coal	$130 to 250	$1.1 to 2.0	$200 to 380	$3.1 to 5.9
Coal Cleaning	3% S Coal	$220 to 370	NA	$220 to 370	$3.4 to 5.7
	2% S Coal	$260 to 420	NA	$260 to 420	$4.0 to 6.5

1/ Reflects a 5 percent discount rate (real) with a 30-year investment lifetime. See Appendix page 11 for an explanation of the equations used. Note that annualized costs calculated using a 5 percent discount rate may understate the capital cost component. A higher discount rate would change the ratio of the cost components such that capital costs would comprise a larger portion of the total annualized cost.

2/ Reflects the one-time costs associated with a million tons of annual SO_2 reductions over a period of 30 years.

SUMMARY OF CALCULATIONS

INDIRECT COSTS

In addition to direct dollar costs, the coal switching control method involves major socio-economic costs. For every one million tons of sulfur dioxide annually removed through coal switching, between 20 and 25 million tons of higher sulfur coal will be displaced by low sulfur coal. An annual reduction of five million tons of sulfur dioxide would displace over 100 million tons of high sulfur coal, about one-eighth of the current coal production of the United States. The portion of the mining industry affected by such a switch would be located primarily in the northern Appalachian and Midwest regions where most of the coal over two percent sulfur is mined. At the same time, increased upward pressure would be placed upon prices for low sulfur coal during a period in which this coal would be in high demand for new industrial boilers and on the coal export market.

Displacing tonnage implies displacing miners from areas where they are now employed. The last column in the table on this chart indicates the number of miners that would be directly affected per million tons of sulfur dioxide annually reduced through coal switching. We estimate that there is no more than a 10 to 15 percent uncertainty in these numbers. We cannot claim that all of these miners would become unemployed; some may move to other coal mining areas, others may not. In fact, total mining employment may increase with the need to open new low sulfur coal mines, although the regional distribution of employment opportunities may change due to the location of the new mines.

Summary of Calculations
Indirect Costs

	Driving Assumptions	Tonnage of Coal Displaced Per Million Tons SO_2 Removed (Million Tons)3/	Miners Affected Per Million tons SO_2 Removed3/
>3%S coal	9 tons/man-day1/ 28 tons/man-day2/ 240 man-days/year	20	5100
>2%S coal		25	6400

1/ Average miner productivity from deep mines. Approximately one-third of "high sulfur" coal (greater than 2 percent sulfur by weight) shipped to utilities is produced from deep mines.

2/ Average miner productivity from surface mines. Approximately two-thirds of "high sulfur" coal (greater than 2 percent sulfur by weight) shipped to utilities is produced from surface mines.

3/ See Appendix page 13 for calculations.

ELECTRICITY COST INCREASES DUE TO SULFUR DIOXIDE EMISSION CONTROL

The ultimate impact of any sulfur dioxide control program aimed at the utility sector will be on consumers of electricity. To estimate the magnitude of the costs that consumers will see, we have calculated the implications of two sulfur dioxide reduction methods: 1) flue gas desulfurization; and 2) coal switching. The chart on page 17 presents estimates for the capital and O&M costs associated with each method. Annualized costs derived using these cost assumptions range between 3 and 9 mills per kilowatt-hour (see Appendix page 14). At the utility itself, this would represent an increase of between 9 and 46 percent over current generating costs.

The regulatory framework governing utility operations allows these additional costs to be passed directly to consumers. By the time transmission and distribution costs are added, consumers would see the 3 to 9 mill increase in busbar costs as no more than a 7 to 26 percent increase in their electricity bills. The actual increase in a consumer electricity bill would depend on the fraction of delivered electricity that is generated by powerplants forced to modify operation to control sulfur dioxide emissions.

Electricity Cost Increase Due to Sulfur Dioxide Emission Control

DRIVING ASSUMPTIONS	INCREMENTAL INCREASE IN GENERATION COST[3]	RANGE OF MAXIMUM INCREASE IN COSTS TO CONSUMER[4]
• 20 to 30 Mills/kwh electricity generation cost [1] • 3 to 5.4 cents/kwh electricity cost to consumer [2]	2.6 to 9.1 Mills/Kwh	4 to 26%

---

[1] Busbar cost of electricity from existing powerplants firing high sulfur coal without scrubbers. (Note: 1 Mill = 0.1 Cent)

[2] The consumer cost includes generation, transmission, and distribution costs. The figures shown here represent rates paid by residential consumers in the ten-state region as of January 1, 1980.

[3] See Appendix page 14 for calculations.

[4] See Appendix page 16 for calculations.

MAXIMUM POTENTIAL CONTROL METHOD EFFECTIVENESS

In this chart, we conclude the presentation of results obtained by our straightforward analysis scheme by showing the maximum potential of each of the control methods to reduce sulfur dioxide emissions. The assumptions that drive these calculations are listed in the chart: the calculations themselves are described in the Appendix. The first column of figures represents the number of million tons of sulfur dioxide emissions that could be controlled if the control method was applied to all coals greater than three percent sulfur used by utilities. The second column assumes the control method is applied to all coals greater than two percent sulfur.

Coal switching or flue gas desulfurization have the potential of reducing sulfur dioxide emissions by between five and ten million tons per year. Coal cleaning, however, is limited to total reductions of two million tons per year or less.

It should be emphasized that the figures shown represent absolute maximums based upon the assumptions shown and do not take into account feasibility constraints associated with particular electric powerplants. If reductions of the order of ten million tons per year or more are desired, it will almost surely be necessary to require additional controls on lower sulfur coals (i.e., below two percent sulfur), to further control industrial users of coal, or to require additional controls on non-coal related sources of sulfur dioxide emissions.

Maximum Potential Control Method Effectiveness
(Million Tons of SO_2 Per Year)

	Driving Assumptions	Maximum Potential Emission Reduction [2]	
		for > 3% S Coal	for >2% S Coal
Coal Switching	1% S coal replaces > 3% S coal (73% Removal) 1% S coal replaces >2% S coal (68% Removal)	4.9	8.0
Flue Gas Desulfurization	85% Removal (> 3% S and >2% S coals)	5.8	10
Coal Cleaning[1]	20% removal (> 3% S and > 2% S coals)	1.4	2.4

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[1] Many of the coals under consideration are already being cleaned. Therefore, the emission reduction numbers shown represent over-estimates.

[2] The totals shown are not additive: each represents the emission reduction resulting from a single, mutually-exclusive control. See Appendix pages 17-18 for calculations.

CONCLUSIONS: DOE ANALYSIS

Page 29 summarizes the major conclusions obtained from our analysis. First, substantial costs are associated with imposing sulfur dioxide control requirements beyond those already in effect. Costs range between $2 and $6 billion for each million tons of sulfur dioxide annually removed. Second, most of the spread in this range can be attributed to "diseconomies of scale." In particular, a small reduction goal could be met by searching for the least cost opportunities to reduce sulfur dioxide emissions and will correspond to costs in the lower portion of this range. As larger reduction increments are sought, these least cost opportunities will be used up and it will be necessary to turn to less cost-effective measures representing the upper portion of the calculated cost range. For example, more expensive scrubbers would have to be installed or expensive-to-clean coal would have to be used. In this context, it is important to note once again that the costs derived in this analysis are minimum costs in the sense that they are based solely upon technical considerations associated with highly cost-effective measures. Actual costs could be considerably higher due to site-specific constraints and/or economic inefficiencies associated with specific regulatory approaches.

Our calculations indicate a ranking of the three control methods, with coal switching being the least expensive (if we ignore indirect costs) and coal cleaning the most expensive. There is considerable overlap among the costs of the three control methods, however, and the cost ranking could be reversed for a particular powerplant at a specific site.

While the direct costs of each of the control methods are comparable, each method has unique problems. Coal cleaning has a serious drawback in that significant reductions of sulfur dioxide emissions cannot be achieved. Flue gas desulfurization also has its drawbacks. There are high capital requirements that would certainly strain the utility sector. In addition, because scrubbers have a long history of maintenance and reliability problems, produce significant quantities of solid waste, and result in decreased energy efficiency, they have not yet gained acceptance by many utilities. In the case of coal switching, relative shifts in the demand for low and high sulfur coals would have a significant impact on the coal industry, particularly through localized displacements of coal miners and increased costs to all low sulfur coal users.

CONCLUSIONS: DOE ANALYSIS

- THE CALCULATIONS YIELD DIRECT COSTS (PRESENT VALUE) COVERING A RANGE BETWEEN $2 AND $6 BILLION PER MILLION TONS SO_2 ANNUALLY REMOVED.
- THE SPREAD IN THIS RANGE CAN BE ATTRIBUTED TO "DISECONOMIES OF SCALE"
    - SMALL REDUCTION INCREMENTS CAN BE ACHIEVED THROUGH LOWER-COST OPPORTUNITIES FOR REDUCING EMISSIONS (CORRESPONDING TO THE LOWER PORTION OF THIS RANGE)
    - LARGE REDUCTION INCREMENTS REQUIRE MORE EXPENSIVE MEASURES FOR REDUCING EMISSIONS (CORRESPONDING TO THE UPPER PORTION OF THIS RANGE)
- DIRECT COSTS (NORMALIZED) ASSOCIATED WITH EACH OF THE CONTROL METHODS ARE COMPARABLE.
- COAL CLEANING CANNOT ACHIEVE SIGNIFICANT REDUCTIONS (I.E.. GREATER THAN 1.5 MILLION TONS SO_2 ANNUALLY)
- BOTH FLUE GAS DESULFURIZATION AND COAL SWITCHING HAVE SIGNIFICANT "INDIRECT" COSTS
    - FLUE GAS DESULFURIZATION: CAPITAL AVAILABILITY, SOLID WASTE DISPOSAL, ENERGY EFFICIENCY LOSSES;
    - SWITCHING: DISPLACEMENT OF TONNAGE AND MINERS, INCREASED COSTS TO ALL LOW SULFUR COAL USERS.

RESULTS FROM CONTRACTOR STUDIES

Page 31 introduces the second phase of this report. Here the sulfur reduction cost estimates derived in the first phase are compared with three larger studies previously conducted for the Department of Energy and the Environmental Protection Agency to assess reduction strategies and costs.

Two of the contractor-performed studies relied upon econometric models of the utility sector. Both of these studies derived costs for distinct regulatory approaches. A third study supplemented these two studies by compiling plant specific data to derive the costs of various levels of sulfur dioxide control. This supplementary study reported costs for the fifty electric powerplants in the United States that are currently emitting the largest quantities of sulfur dioxide.

Since each of the three contractor studies used different costing methodologies, it was necessary to readjust their cost figures so that they can be compared to one another and to the results obtained from the analysis already presented in this briefing. A description of the readjustment process is provided in the Appendix (see pages 19-20) along with further details of the specific cost data.

RESULTS FROM CONTRACTOR STUDIES

- TWO MODEL-BASED STUDIES:
  - CONTRACTORS: TEKNEKRON AND ICF
  - PURPOSE: TO COMPARE COSTS OF ALTERNATIVE REGULATORY APPROACHES
- SUPPLEMENTARY STUDY: COSTS ASSOCIATED WITH THE 50 LARGEST SO_2 EMITTERS IN U.S. (POWERPLANTS)
  - CONTRACTOR: PEDCO
  - PURPOSE: TO OBTAIN DATA RELEVANT TO SPECIFIC PLANTS.
- THESE STUDIES PROVIDE A COST DATA BASE ACROSS A RANGE OF EMISSION REDUCTIONS
- FOR PURPOSES OF COMPARISON WITH SIMPLE ANALYSIS, RESULTS HAVE BEEN NORMALIZED AND PRESENTED AS PRESENT VALUES.

This chart depicts the control cost estimates from the three contractor studies and DOE analysis. The horizontal axis indicates levels of emission reduction, in millions of tons of sulfur dioxide. The left vertical axis shows "present value" costs (in billions of dollars per million tons removed) and the right vertical axis shows the equivalent annual costs (in dollars per ton). The data points are keyed by contractor: the darkened circles represent results obtained from the ICF analysis; triangles represent Teknekron's results; and open circles represent PEDCO's results. The vertical lines show the range of costs obtained through the DOE analysis: their position on the horizontal axis represents fifty percent of the maximum reduction potential of the control method. The letters C,S, and D designate costs associated with coal cleaning, coal switching, or flue gas desulfurization, respectively. Undesignated symbols generally represent costs associated with a combination of control methods, although coal switching predominates in most cases.

The pair of dashed lines identifies a range of cost estimates. The lower line generally represents the costs associated with a regulation strategy which targets only those states and specific powerplants where sulfur dioxide reductions could be achieved for the least cost per ton controlled. Since cost-effective regulations are difficult to achieve in practice, the upper line represents actual regulations, which often compromise economic efficiency for equity concerns and administrative simplicity and are, therefore more costly.

The upward trend of the dashed lines can be attributed to "diseconomies of scale": as greater emission reductions are sought, the incremental costs of control increase. For example, higher reductions could require both scrubbing and switching to be employed at the same powerplant.

The control costs obtained by the DOE analysis generally agree with the control costs obtained by the more detailed contractor analyses.[1] Further, the results seem to indicate that coal cleaning is the least cost-effective and coal switching is the most cost-effective. Such a conclusion is not warranted, however, since indirect costs and possible benefits of particular methods are not considered. For example, benefits associated with the pre-cleaning of coal--lower ash content and more uniform quality--lower O&M costs to utilities. If these benefits are taken into account, the costs of coal cleaning attributable to sulfur dioxide removal may be comparable to those associated with other control methods. The uncertainties in all of the cost analyses indicate that the design of cost-effective regulations would allow individual utilities to select control methods best suited to their particular facilities.

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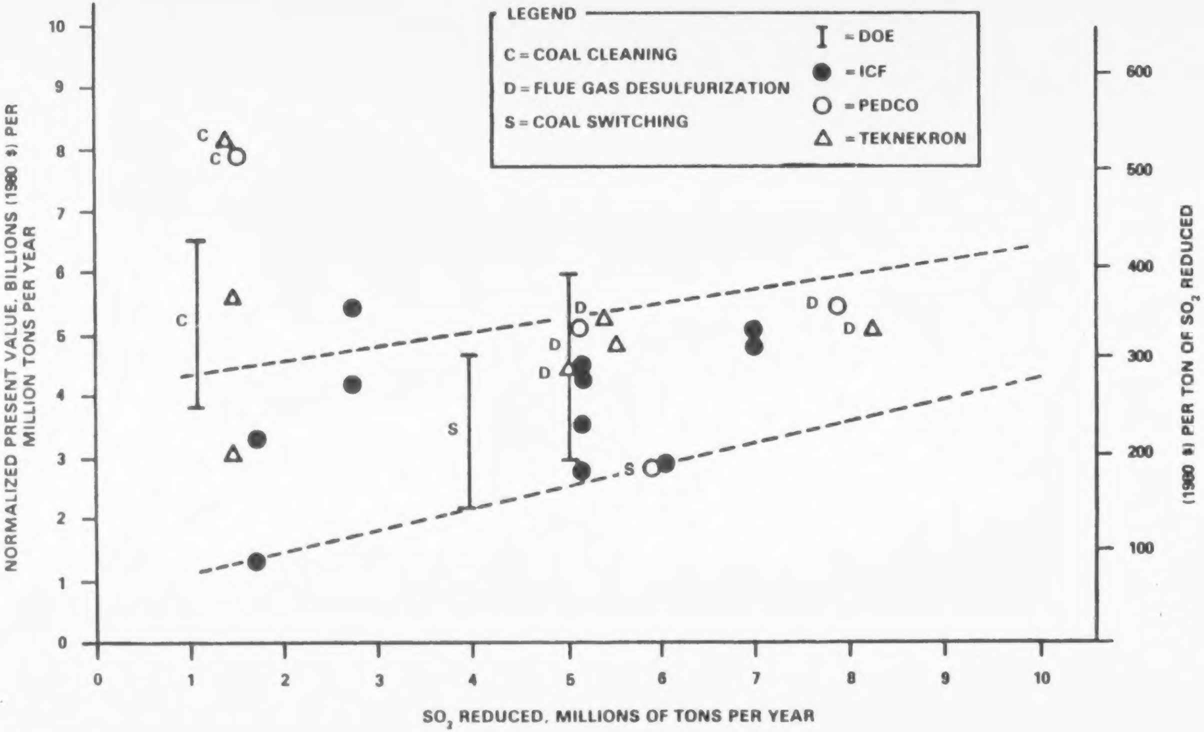
[1] Of course, there are uncertainties associated with the point estimates due to variations in the input data, modelling techniques and costing methodologies used by each contractor. The data shown in this chart have been adjusted (see Appendix pages 19-20) to account for different costing methods, however, small residual errors may remain. Uncertainties associated with input data and modelling techniques may be significant. Moreover, experience indicates that model analyses are likely to underestimate costs due to simplifying assumptions.

SUMMARY AND COMPARISON OF CONTRACTOR STUDIES



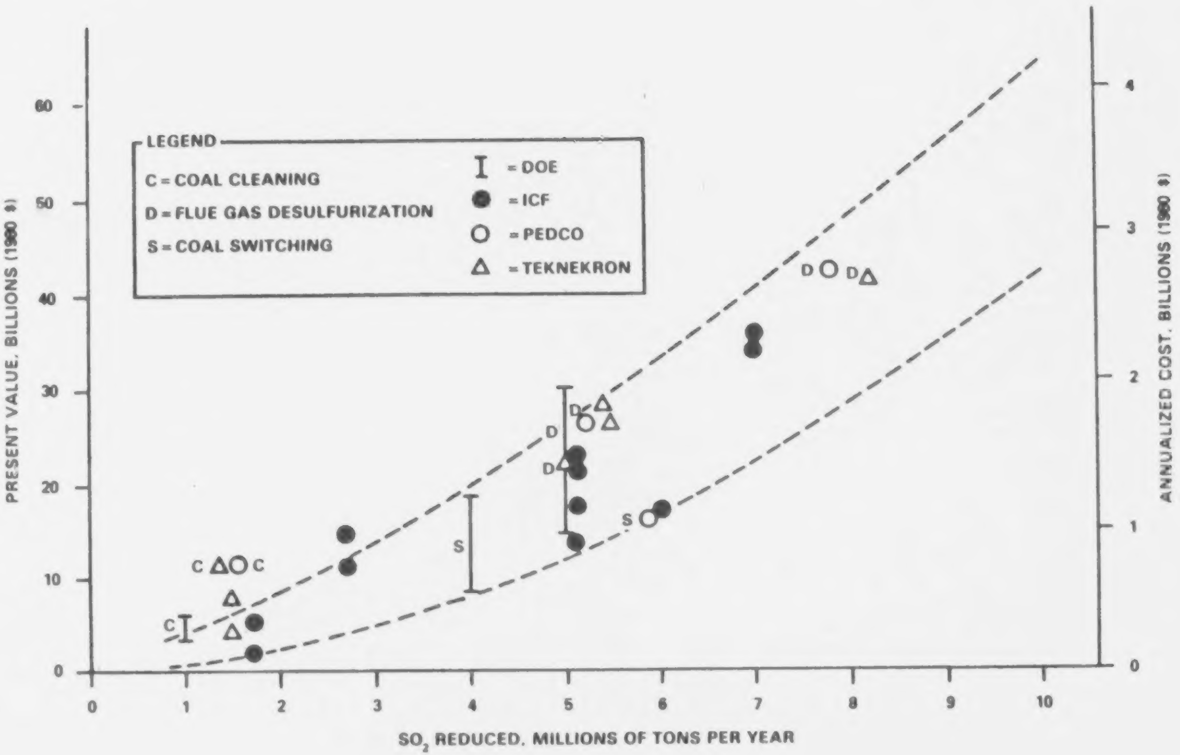
Total Costs

Although we have focused, for the purpose of analysis, on normalized costs (costs per unit of emission reduction), total costs are far more relevant to any decision to control sulfur dioxide emissions. This chart presents the same information as the previous chart but now the vertical axes represent the total present value (left scale) or annualized cost (right scale) of obtaining the emission reductions indicated along the horizontal scale. The pair of dashed lines curve upward, demonstrating the disproportionate rate at which costs increase as higher levels of emission reduction are sought.

Reading the chart, the costs of reducing sulfur dioxide emissions range between:

- $1 to $2 billion annually for a 5 million ton annual reduction (present value: $15 to $30 billion)
- $3 to $4 billion annually for a 10 million ton annual reduction (present value: $45 to $65 billion)

TOTAL COSTS


LEGEND
C = COAL CLEANING
D = FLUE GAS DESULFURIZATION
S = COAL SWITCHING
I = DOE
● = ICF
○ = PEDCO
△ = TEKNEKRON
PRESENT VALUE, BILLIONS (1980 $)
0
10
20
30
40
50
60
ANNUALIZED COST, BILLIONS (1980 $)
0
1
2
3
4
SO₂ REDUCED, MILLIONS OF TONS PER YEAR
0
1
2
3
4
5
6
7
8
9
10
C
C
C
S
D
D
D
S
D
D

MINIMUM ANTICIPATED COSTS TO CONTROL SO_2 EMISSIONS

This chart takes two levels of sulfur dioxide control from the previous chart and summarizes our best estimates of the minimum costs expected to be incurred to reach those control levels. The first column of numbers presents the costs associated with a decision to reduce annual sulfur dioxide emissions by five million tons. The second column presents the costs associated with a decision to reduce annual emissions by ten million tons.

The figures in each column represent alternative ways of describing the minimum costs that would be incurred by a decision to control sulfur dioxide emissions.

The first two costs shown in each column represent the annualized costs in 1980 dollars and the present value of the costs, again in 1980 dollars. These two accounting methods are often used in cost-benefit analyses in both the Government and private industry to compare alternative policies or investments. They are important accounting tools for decision makers; however, the costs they predict do not reflect actual expenditures.

The third row of numbers in each column represents our best estimate of the actual amount of dollars that would be spent over a 30 year period if there was no inflation. This type of cost reporting, i.e., uninflated dollars, is useful to those unfamiliar with the accounting intricacies associated with annualized or present value cost calculation procedures. The bottom row of costs in each column represents an estimate of the actual amount of dollars that would be spent over a 30 year period. To calculate these figures, we have assumed that the inflation rate over the entire 30 year period is only 6 percent. Higher rates of inflation would raise these figures while lower rates would decrease them.

There are, of course, uncertainties associated with these "best estimate" figures. Although a rigorous uncertainty analysis has not been done as part of this cost study, examination of the underlying data indicates that an uncertainty band of 25 percent is a reasonable estimate. It should be recognized, however,that the overall methodology used in this report generally underestimates rather than overestimates costs.

MINIMUM ANTICIPATED COSTS TO CONTROL SO_2 EMISSIONS

COST METHOD	5 MILLION TON ANNUAL REDUCTION	10 MILLION TON ANNUAL REDUCTION
Annualized (1980 $)	$1.3 Billion	$3.6 Billion
Present Value (1980 $)	$20 Billion	$55 Billion
30-Year Expenditures (1980 $)	$40 Billion	$110 Billion
30-Year Expenditures (Nominal $)*	$70-100 Billion	$200-300 Billion

* These figures assume a constant inflation rate of 6 percent; the range reflects differing ratios of capital and annual costs.

CONCLUSIONS

Pages 39 through 41 summarize the conclusions of this report.

CONCLUSIONS

- WHEN PLACED ON A CONSISTENT ACCOUNTING BASIS, THE VARIOUS COST ANALYSES EXAMINED IN THIS REPORT ARE COMPATIBLE WITH ONE ANOTHER.

- THE CONTRACTOR ANALYSES DEMONSTRATE THAT CONTROL COSTS ARE HIGHLY SENSITIVE TO THE REGULATORY APPROACH APPLIED TO OBTAIN THE DESIRED EMISSION REDUCTION.

- CONTROL COSTS RISE DISPROPORTIONALLY AS GREATER LEVELS OF CONTROL ARE SOUGHT. FOR LARGER REDUCTIONS, LESS SULFUR DIOXIDE IS CONTROLLED PER DOLLAR EXPENDED SINCE:

  - CONTROL MEASURES MUST BE FORCED UPON UTILITIES BURNING LOWER SULFUR COALS OR HARD-TO-WASH COALS; AND

  - SHIFTS IN COAL SUPPLY AND DEMAND CAUSE COAL PRICES TO RISE.

- THE MINIMUM COSTS ARE LARGE FOR THE MASSIVE CONTROL PROGRAMS CURRENTLY ADVOCATED BY PROPONENTS OF IMMEDIATE CONTROL. FOR AN ANNUAL REDUCTION OF:

5 MILLION TONS	10 MILLION TONS
$1.3 BILLION (ANNUALIZED)	$3.6 BILLION (ANNUALIZED)
$20 BILLION (PRESENT VALUE)	$55 BILLION (PRESENT VALUE)
$40 BILLION (30-YEAR COSTS: REAL 1980 $)	$110 BILLION (30-YEAR COSTS: REAL 1980 $)
$70-100 BILLION (30-YEAR COSTS: NOMINAL $)	$200-300 BILLION (30-YEAR COSTS: NOMINAL $)

- THESE COSTS WILL BE BORNE PRIMARILY BY TEN MIDWEST STATES

- IT IS OUR JUDGMENT THAT THE ACTUAL COSTS OF CONTROL MEASURES WILL BE MUCH HIGHER THAN THOSE REPORTED HEREIN.
    - MAJOR COST ELEMENTS SUCH AS TRANSPORTATION COSTS AND THE PRICE RESPONSE DUE TO DISRUPTION OF THE COAL MARKET MAY BE SERIOUSLY UNDERESTIMATED.
    - ECONOMICALLY EFFICIENT REGULATIONS ARE UNLIKELY TO BE ACHIEVED IN PRACTICE.
- OF THE THREE CONTROL METHODS EXAMINED, NONE OFFERS SUBSTANTIAL ADVANTAGES OVER OTHERS.
- UNLESS EXTREMELY SMALL REDUCTIONS ARE SUFFICIENT, COAL CLEANING ALONE IS NOT A SATISFACTORY CONTROL METHOD.
- FLUE GAS DESULFURIZATION MAY BE AVOIDED BY UTILITIES DUE TO:
    - HISTORY OF MECHANICAL FAILURES AND MAINTENANCE REQUIREMENTS
    - CAPITAL INVESTMENT REQUIREMENTS
    - WASTE DISPOSAL PROBLEMS AND ENERGY EFFICIENCY LOSSES
- COAL SWITCHING INVOLVES SIGNIFICANT INDIRECT COSTS. FOR EACH MILLION TONS OF SULFUR DIOXIDE EMISSIONS REDUCED ANNUALLY,
    - 20 TO 25 MILLION TONS OF COAL CAPACITY WILL BE DISPLACED
    - 5100 To 6400 MINERS WILL BE AFFECTED

- IT IS OUR JUDGMENT THAT THE UNCERTAINTY IN THE COSTS REPORTED IN THIS STUDY IS APPROXIMATELY 25 PERCENT.
    - THIS UNCERTAINTY IS INSIGNIFICANT WHEN COMPARED TO THE UNCERTAINTIES ASSOCIATED WITH CURRENT PROJECTIONS OF THE HEALTH. ENVIRONMENTAL OR ECONOMIC BENEFITS THAT WOULD BE ACHIEVED BY SUCH MASSIVE EMISSION REDUCTIONS. FOR EXAMPLE. REDUCING SULFUR DIOXIDE EMISSIONS BY TEN MILLION TONS PER YEAR MAY ONLY MARGINALLY DECREASE THE ACIDITY OF PRECIPITATION FALLING ON SENSITIVE AREAS.

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Calculations for Average Sulfur Content of Coal

Average sulfur content of coal is derived by summing the quantity of sulfur in various categories of coal and dividing by the total tonnage represented within the categories. Thus:

$(Q_x) \cdot (C_x) = S_x$ where: Q_x = percent sulfur content in category "x" coal

C_x = million tons of category "x" coal consumed in 1979

S_x = million tons of sulfur in category "x" coal

and:

$(S_T) \div (C_T) = A_T$ where: S_T = total million tons of sulfur, i.e., $S_x + S_y + \ldots S_n = S_T$

C_T = total million tons of coal, i.e., $C_x + C_y + \ldots C_n = C_T$

A_T = weighted average percent sulfur content

For >3% Sulfur Coal:

Coal Category	% Sulfur Content	Quantity Consumed	Quantity of Sulfur
3.0-3.5% S	3.25	66 million tons	2.15 million tons
3.5-4.0% S	3.75	23	0.86
4.0-4.5% S	4.25	17	0.72
4.5-5.0% S	4.75	0	0
5.0 & above	5.50	6	0.33
		112 million tons	4.06 million tons

(4.06 million tons sulfur) ÷ (112 million tons coal) = 3.6 average % sulfur

For >2% Sulfur Coal:

Coal Category	% Sulfur Content	Quantity Consumed	Quantity of Sulfur
2.0-3.0% S	2.50	89 million tons	2.23 million tons
3.0 & above	3.6	112	4.06
		201 million tons	6.29 million tons

(6.29 million tons sulfur) ÷ (201 million tons coal) = 3.1 average % sulfur

For the purpose of the following calculations, the "weighted average sulfur content" will be used to identify the quantity of sulfur in the coal categories being examined. Thus, the quantity of sulfur in all coal greater than 3 percent sulfur will be defined as 3.6 percent. The quantity of sulfur in all coal greater than 2 percent sulfur will be defined as 3.1 percent.

Calculations for Coal Switching

A powerplant switching to low sulfur coal to reduce its sulfur dioxide emissions encounters both one-time capital costs and annual operation and maintenance (O&M) costs. Although either cost component can be expressed in several ways, we are concerned here with two representations: 1) costs per unit of coal switched, and 2) costs per unit of sulfur dioxide reduced.

I. CAPITAL COSTS

A. Capital costs per unit of coal switched can be calculated by determining the quantity of coal required to produce the power output of the plant, and multiplying this factor by the cost of upgrading precipitators and coal grinders. Such equipment improvements are necessary to enable the plant to burn low-sulfur coal and maintain compliance with particulate matter control regulations.

Thus: $$\frac{\text{Capital Costs}}{\text{million tons of coal switched per year}} = K \times U \times E \times CE \times H$$

where: K = equipment capital charge per kilowatt of capacity
U = capacity utilization per year
E = electricity conversion factor: kilowatt-hour/BTU (electrical)
CE = heat conversion efficiency: BTU (electrical)/BTU (thermal)
H = heat content of coal: BTU (thermal)/million tons of coal

For our analysis: K = \$21 to \$50/kw
U = 60% or 1 yr/(0.6 x 8760 hrs)
E = 1 Kwh/3412 BTU (electrical)
CE = 0.3 BTU (electrical)/1.0 BTU (thermal)
H = 24 trillion BTU (thermal)/million tons of coal

Therefore:

$$\frac{\text{Capital Costs}}{\text{million tons of coal switched per year}} = (21 \text{ to } 50)\times\left(\frac{1}{0.6 \times 8760}\right)\times\left(\frac{1}{3412}\right)\times(0.3)\times(24 \times 10^{12})$$
$$= \$8.45 \text{ million to } \$20.11 \text{ million}$$

B. Capital costs per unit of sulfur dioxide reduced are determined by dividing the previous results by a conversion factor translating tons of coal switched into tons of SO_2 removed.

Thus: $$\frac{\text{Capital Costs}}{\text{million tons of } SO_2 \text{ removed per year}} = \left[\frac{\text{Capital Costs}}{\text{million tons of coal}}\right] \div \underbrace{(S \times EF \div W)}_{\text{(Conversion Factor)}}$$

where: S = change in percent sulfur
EF = emission factor: pound SO_2/ton of coal
W = weight conversion factor: pound/ton

For our analysis: S = 2.6% change in sulfur from switching > 3% S coal to 1% S coal, i.e., (3.6 - 1.0)

or

= 2.1% change in sulfur from switching > 2% S coal to 1% S coal, i.e., (3.1 - 1.0)

EF = 38 lb. SO_2/ton coal
W = 2000 lb./ton

Therefore:

$$\frac{\text{Capital Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = [8.45 \times 10^6 \text{ to } 20.11 \times 10^6] \div (2.6 \times 38 \div 2000)$$

= \$171 million to \$407 million (for switching > 3% S coal)

or

= $[8.45 \times 10^6 \text{ to } 20.11 \times 10^6] \div (2.1 \times 38 \div 2000)$

= \$212 million to \$504 million (for switching > 2% S coal)

II. O&M COSTS

A. O&M costs per unit of coal switched reflect the fact that low sulfur coal is more costly than high sulfur coal. Therefore, we express O&M costs as the incremental difference in coal price.

Therefore:

$$\frac{\text{Annual O\&M Costs}}{\text{million tons of coal switched per year}} = \$6 \text{ million to } \$12 \text{ million (for switching} > 3\% \text{ S coal)}$$

or

= \$5 million to \$11 million (for switching > 2% S coal)

B. O&M costs per unit of sulfur dioxide reduced are determined by dividing the previous results by the conversion factor, introduced in Section I.B., translating tons of coal switched into tons of SO_2 reduced.

Thus:

$$\frac{\text{Annual O\&M Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = \left[\frac{\text{Annual O\&M Costs}}{\text{million tons of coal switched}}\right] \div (S \times EF \div W)$$

where: S = change in percent sulfur (2.6% when switching > 3% S coal; 2.1% when switching > 2% S coal)
EF = emission factor: pound SO_2/ton of coal (38)
W = weight conversion factor: pound/ton (2000)

Therefore:

$$\frac{\text{Annual O\&M Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = [6 \times 10^6 \text{ to } 12 \times 10^6] \div (2.6 \times 38 \div 2000)$$

= \$121 million to \$243 million (for switching > 3% S coal)

or

= $[5 \times 10^6 \text{ to } 11 \times 10^6] \div (2.1 \times 38 \div 2000)$

= \$125 million to \$276 million (for switching > 2% S coal)

Calculations for Flue Gas Desulfurization

To illustrate the costs of flue gas desulfurization, we have examined a wet scrubber system installed on an existing high sulfur coal-burning powerplant.* A powerplant using a flue gas scrubber to reduce its sulfur dioxide emissions encounters both one-time capital costs and annual operation and maintenance (O&M) costs. Although either cost component can be expressed in several ways, we are concerned here with two representations: 1) costs per unit of coal scrubbed, and 2) costs per unit of sulfur dioxide reduced.

I. CAPITAL COSTS

A. Capital costs per unit of coal scrubbed can be calculated by determining the quantity of coal required to produce the power output of the plant, and multiplying this factor by the cost of a wet scrubber.

Thus:

$$\frac{\text{Capital Costs}}{\text{million tons of coal scrubbed per year}} = K \times U \times E \times CE \times H$$

where: K = scrubber capital charge per kilowatt of capacity
U = capacity utilization per year
E = electricity conversion factor: kilowatt-hour/BTU (electrical)
CE = heat conversion efficiency: BTU (electrical)/BTU (thermal)
H = heat content of coal: BTU (thermal)/million tons of coal

For our analysis: K = $140 to $250/kw
U = 60% or 1 yr/(0.6 x 8760 hrs)
E = 1 Kwh/3412 BTU (electrical)
CE = 0.3 BTU (electrical)/1.0 BTU (thermal)
H = 24 trillion BTU (thermal)/million tons of coal

Therefore:

$$\frac{\text{Capital Costs}}{\text{million tons of coal scrubbed per year}} = (140 \text{ to } 250) \times \left(\frac{1}{0.6 \times 8760}\right) \times \left(\frac{1}{3412}\right) \times (0.3) \times (24 \times 10^{12})$$

$$= \$56.21 \text{ million to } \$100.37 \text{ million}$$

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*Spray dryers are somewhat less expensive than wet scrubbers, however, these lower costs appear to be offset by a lower removal efficiency. Essentially, then, the overall costs of spray dryers overlap with the costs of wet scrubbers.

B. Capital costs per unit of sulfur dioxide reduced are determined by dividing the previous results by a conversion factor translating tons of coal scrubbed into tons of SO_2 removed.

Thus: $$\frac{\text{Capital Costs}}{\text{million tons of } SO_2 \text{ removed per year}} = \left[\frac{\text{Capital Costs}}{\text{million tons of coal}}\right] \div \underbrace{(S \times EF \div W)}_{\text{(Conversion Factor)}}$$

where: S = change in percent sulfur
EF = emission factor: pound SO_2/ton of coal
W = weight conversion factor: pound/ton

For our analysis: S = 3.06% change in sulfur from 85% scrubbing of >3% S coal i.e., (3.6 x 0.85)

or

= 2.64% change in sulfur from 85% scrubbing of >2% S coal i.e., (3.1 x 0.85)

EF = 38 lb. SO_2/ton coal
W = 2000 lb./ton

Therefore:

$$\frac{\text{Capital Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = [56.21 \times 10^6 \text{ to } 100.37 \times 10^6] \div (3.06 \times 38 \div 2000)$$

= \$967 million to \$1726 million (for scrubbing >3% S coal)

or

$$= [56.21 \times 10^6 \text{ to } 100.37 \times 10^6] \div (2.64 \times 38 \div 2000)$$

= \$1121 million to \$2001 million (for scrubbing >2% S coal)

II. O&M COSTS

A. O&M costs per unit of coal scrubbed are calculated as a function of the amount of electricity produced by the powerplant.

Thus: $$\frac{\text{Annual O\&M Costs}}{\text{million tons of coal scrubbed per year}} = G \times E \times CE \times H \times D$$

Where: G = cost of scrubber O&M per kilowatt-hour generated
E = electricity conversion factor: kilowatt-hr/BTU (electrical)
CE = heat conversion efficiency: BTU (electrical)/BTU (thermal)
H = heat content: BTU (thermal)/million tons of coal
D = cost conversion factor: dollar/mill

For our analysis: G = 3 to 6 mills/Kwh
E = kwh/3412 BTU (electrical)
CE = 0.3 BTU (electrical)/1.0 BTU (thermal)
H = 24 trillion BTU (thermal)/million tons of coal
D = 1 \$/1000 mills

Therefore:

$$\frac{\text{Annual O\&M Costs}}{\text{million tons of coal scrubbed per year}} = [3 \text{ to } 6] \times \left(\frac{1}{3412}\right) \times (0.3) \times (24 \times 10^{12}) \times \left(\frac{1}{1000}\right)$$

$$= \$6.33 \text{ million to } \$12.66 \text{ million}$$

B. O&M costs per unit of sulfur dioxide reduced are determined by dividing the previous results by the conversion factor, introduced in Section I.B., translating tons of coal scrubbed into tons of SO_2 reduced.

Thus: $$\frac{\text{Annual O\&M Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = \left[\frac{\text{Annual O\&M Costs}}{\text{million tons of coal scrubbed}}\right] \div (S \times EF \div W)$$

where: S = change in percent sulfur (3.06% for scrubbing >3% S coal; 2.64% for scrubbing >2% S coal)
EF = emission factor: pound SO_2/ton of coal (38)
W = weight conversion factor: pound/ton (2000)

Therefore:

$$\frac{\text{Annual O\&M Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = [6.33 \times 10^6 \text{ to } 12.66 \times 10^6] \div (3.06 \times 38 \div 2000)$$

$$= \$109 \text{ million to } \$218 \text{ million (for scrubbing} > 3\% \text{ S coal)}$$

or

$$= [6.33 \times 10^6 \text{ to } 12.66 \times 10^6] \div (2.64 \times 38 \div 2000)$$

$$= \$126 \text{ million to } \$252 \text{ million (for scrubbing} > 2\% \text{ S coal)}$$

Calculations for Coal Cleaning

For this analysis, a powerplant burning mechanically cleaned coal to reduce its sulfur dioxide emissions is assumed to encounter only increased fuel costs. Although capital expenditures are required for coal cleaning equipment and increased boiler efficiency may result from burning cleaned coal, for simplicity we will assume such costs and benefits to be incorporated in the cost of the cleaned coal. We will express the costs in two ways: 1) costs per unit of coal cleaned, and 2) costs per unit of sulfur dioxide reduced.

A. Annual costs per unit of coal cleaned are represented simply as the incremental cost of more expensive cleaned coal.
For our analysis, it is assumed that cleaned coal costs \$3 to \$5 per ton more than uncleaned coal.

Therefore: $\frac{\text{Annual Costs}}{\text{million tons of coal cleaned per year}}$ = \$3 million to \$5 million

B. Annual costs per unit of sulfur dioxide reduced are determined by dividing the previous values by the conversion factor translating tons of coal cleaned into tons of SO_2 reduced.

$$\text{Thus: } \frac{\text{Annual Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = \left[\frac{\text{Annual costs}}{\text{million tons of coal cleaned}}\right] \div (S \times EF \div W)$$

Where S = change in percent sulfur content
EF = emission factor: pound SO_2/ton of coal
W = weight conversion factor: pound/ton

For our analysis: S = 0.72% change in sulfur content after 20% cleaning of > 3% S coal, i.e., (3.1 x 0.20)
or
= 0.62% change in sulfur content after 20% cleaning of > 2% S coal, i.e., (3.1 x 0.20)
EF = 38 lb. SO_2/ton coal
W = 2000 lb./ton

Therefore: $\frac{\text{Annual Costs}}{\text{million tons of } SO_2 \text{ reduced per year}}$

$= [3 \times 10^6 \text{ to } 5 \times 10^6] \div (0.72 \times 38 \div 2000)$
= \$219 million to \$365 million (for cleaning > 3% S coal)

or

$= [3 \times 10^6 \text{ to } 5 \times 10^6] \div (0.62 \times 38 \div 2000)$
= \$255 million to \$424 million (for cleaning > 2% S coal)

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Calculations for Present Value and Annualized Costs

To express one-time capital costs and annual O&M costs as a single cost figure, two basic methods may be used. The present value method discounts the annual stream of O&M costs as a single cost and adds the capital costs to represent the total sum needed to cover current and future costs over the life of the investment. The annualized cost method apportions the capital costs into annual payments and adds the O&M costs to represent the complete cost to be paid in each year of the investment life.

I. PRESENT VALUE (PV)

$$PV = C + \sum_{m=1}^{n} \frac{A_m}{(1+d)^m}$$

where:
C = capital costs
A_m = O&M costs in year m (1980 $)
n = number of years in investment lifetime
d = discount rate

For our analysis:
$n = 30$ years
$d = 5$ percent (real)
A_m is constant each year: $A_m = A$

Therefore:

$$PV = C + A(15.4)$$

II. ANNUALIZED COST (AC) in year m is expressed by the following:

$$AC_m = \frac{C}{\sum_{m=1}^{n} \frac{1}{(1+d)^m}} + A_m$$

where:
C = capital costs
A_m = O&M costs in year m (1980 $)
n = number of years in investment lifetime
d = discount rate

For our analysis: $n = 30$ years
$d = 5$ percent (real)
A_m is constant each year: $A_m = A$

Therefore:

$$AC_m = \frac{C}{15.4} + A \qquad \text{and is constant each year.}$$

Calculations for Indirect Costs of Coal Switching

A shift in demand away from high sulfur coal and toward low sulfur coal will affect miners of high sulfur coal. To estimate the magnitude of the effect, we must first determine the number of miners employed per ton of coal mined. Using miner productivity factors of 9 tons of coal per day for deep mines and 28 tons per day for surface mines, and assuming a miner works 240 days per year, we derive the following:

(9 tons of coal mined/day) × (240 man-days/year) = 2160 tons of coal/miner/year from deep mines
(28 tons of coal mined/day) × (240 man-days/year) = 6720 tons of coal/miner/year from surface mines

Assuming that one-third of high sulfur coal is deep-mined and two-thirds is surface mined, we can express the number of miners as a function of the quantity of coal switched:

$$\frac{\frac{1}{3}\left(\text{1 million tons of coal switched}\right)}{\text{2160 tons of coal/miner/year}} + \frac{\frac{2}{3}\left(\text{1 million tons of coal switched}\right)}{\text{6720 tons of coal/miner/year}} = \text{254 miners/million tons of coal switched/year}$$

Ultimately, we can express the indirect costs of coal switching (i.e., effects on miners) as a function of the benefits of coal switching (i.e., sulfur dioxide reduced). To do this, however, we need to know the change in the sulfur dioxide emission rate from switching to low sulfur coal. Referring to Appendix page 17, where sulfur dioxide emission rates are derived, we can calculate the following:

$$\left(\frac{0.0684\ \text{ton}\ SO_2}{\text{ton}\ >3\%\ \text{sulfur coal}}\right) - \left(\frac{0.0190\ \text{ton}\ SO_2}{\text{ton}\ 1\%\ \text{sulfur coal}}\right) = \left(\frac{0.0494\ \text{ton}\ SO_2}{\text{ton coal switched}}\right)\ \text{Decrease in emission rate from switching}\ >3\%\ \text{sulfur coal to}\ 1\%\ \text{sulfur coal}^*$$

while

$$\left(\frac{0.0589\ \text{ton}\ SO_2}{\text{ton}\ >2\%\ \text{sulfur coal}}\right) - \left(\frac{0.0190\ \text{ton}\ SO_2}{\text{ton}\ 1\%\ \text{sulfur coal}}\right) = \left(\frac{0.0399\ \text{ton}\ SO_2}{\text{ton coal switched}}\right)\ \text{Decrease in emission rate from switching}\ >2\%\ \text{sulfur coal to}\ 1\%\ \text{sulfur coal}^*$$

Now, dividing these two emission factors into the number of miners affected per ton of coal switched, we obtain the following:

$$(\text{254 miners/million tons of coal switched/year}) \div \left(\frac{0.0494\ \text{ton}\ SO_2\ \text{reduced}}{\text{ton}\ >3\%\ \text{sulfur coal switched per year}}\right) = 5132\ \text{miners/ton}\ SO_2\ \text{reduced/year}$$

and

$$(\text{254 miners/million tons of coal switched/year}) \div \left(\frac{0.0399\ \text{ton}\ SO_2\ \text{reduced per year}}{\text{ton}\ >2\%\ \text{sulfur coal switched per year}}\right) = 6354\ \text{miners/ton}\ SO_2\ \text{reduced/year}$$

---

* Note that the reciprocal of these expressions yields the value for tons of coal switched per ton of sulfur dioxide removed:

$$\frac{20.24\ \text{tons}\ >3\%\ \text{sulfur coal switched}}{\text{ton sulfur dioxide removed}}\quad \text{and}\quad \frac{25.01\ \text{tons}\ >2\%\ \text{sulfur coal switched}}{\text{ton sulfur dioxide removed}}$$

Calculations for Increase in Electricity Generation Costs

To estimate the increased cost of generating electricity at powerplants instituting sulfur dioxide controls, we will examine two control methods: (I) flue gas desulfurization; and (II) switching to low sulfur coal.

I. Flue Gas Desulfurization (FGD)

According to the cost assumptions presented on page 17 of the text, the capital costs of an FGD system range from $140 to $250 per kilowatt of capacity. Expressed in terms of the kilowatt-hours generated per year (at a 60 percent plant utilization rate), these costs are derived as follows:

$$\left[(\$140 \text{ to } \$250/\text{kw}) \div (0.6 \times 8760 \text{ hrs/yr})\right] \times (10^3 \text{ mills/\$}) = 26.6 \text{ to } 47.6 \text{ mills/kwh/yr}$$

The annual operation and maintenance costs (O&M) associated with an FGD system range from 3 to 6 mills per kilowatt-hour. To express the capital and O&M cost components as a range of total annualized costs, a 5 percent (real) discount rate is applied over a 30-year investment lifetime (as shown in the formula on Appendix page II-12) to yield the following:

$$\text{Annualized Cost}_{FGD} = \left[\frac{(26.6 \text{ to } 47.6 \text{ mills/kwh})}{15.4}\right] + (3 \text{ to } 6 \text{ mills/kwh}) = 4.73 \text{ to } 9.09 \text{ mills/kwh}$$

II. Switching to Low Sulfur Coal (SW)

Returning to the cost assumptions presented on page 17 of the text, the capital costs for upgrading plant equipment to handle low sulfur coal range from $21 to $50 per kilowatt of capacity. Expressed in terms of the kilowatt-hours generated per year (at a 60 percent utilization rate), these costs are derived as follows:

$$\left[(\$21 \text{ to } \$50/\text{kw}) \div (0.6 \times 8760 \text{ hrs/yr})\right] \times (10^3 \text{ mills/\$}) = 4.00 \text{ to } 9.51 \text{ mills/kwh/yr}$$

The annual operation costs for switching all coal greater than two percent sulfur to one percent sulfur coal are reflected in the higher purchase price of low sulfur coal. The price of greater than two percent sulfur coal ranges from $5 to $11 per ton, taking the average between prices for coal greater than three percent sulfur and prices for coal between two and three percent sulfur. To express these costs as a function of the kilowatt-hours generated per year, a factor relating coal burned to electricity generated is derived from the following formula:

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$$\frac{\text{Kilowatt-hours}}{\text{ton of coal}} = H \times C \div E \qquad \text{Where: } H = \text{heat content of coal} = 24 \times 10^6 \text{ Btu (thermal)/ton coal}$$

$$= (24 \times 10^6) \times (0.3) \div (3412) \qquad C = \text{heat conversion efficiency} = 0.3 \text{ Btu (electrical)/Btu(thermal)}$$

$$= 2110 \qquad E = \text{electricity conversion factor} = 3412 \text{ Btu (electrical)/kwh}$$

Using the factor of 2110 kilowatt-hours generated per ton of coal burned, the annual operating costs associated with burning low sulfur coal are derived as follows:

$$\left[(\$5 \text{ to } \$11/\text{ton}) \div (2110 \text{ kwh/ton})\right] \times (10^3 \text{ mills/\$}) = 2.37 \text{ to } 5.21 \text{ mills/kwh}$$

To express the capital and annual operating cost components of coal switching as a range of total annualized costs, the formula on Appendix pages 11-12 is used to obtain the following:

$$\text{Annualized Costs}_{SW} = \left[\frac{(4.00 \text{ to } 9.51 \text{ mills/kwh})}{15.4}\right] + (2.37 \text{ to } 5.21 \text{ mills/kwh}) = 2.63 \text{ to } 5.83 \text{ mills/kwh}$$

Calculations for Increase in Electricity Cost to Consumer

To estimate the maximum cost impact of sulfur dioxide controls on consumers of electricity, we will assume that the entire increase in electricity generating costs (derived on the previous two pages) is passed-through to the consumer. Further, assume that 85 percent of the electricity delivered to the consumer is generated by coal-burning powerplants instituting sulfur dioxide controls. (In actuality, this percentage varies from area to area, and in most cases less than 85 percent of the powerplants serving a given consumer would be high sulfur coal-burning plants subject to sulfur dioxide controls.)

In effect, then, the consumers in our example would see 85 percent of the increase in generating costs reflected in their electricity bills. To compare this increase to the amount consumers are paying now, page 25 of the text states that residential consumers in the 10-state region pay between 30 and 54 mills per kilowatt-hour for their electricity. Thus, the estimated cost increase is derived as follows:

$$\frac{(2.6 \text{ to } 9.1 \text{ mills/kwh}) \times (0.85)}{(30 \text{ to } 54 \text{ mills/kwh})} = 4 \text{ to } 26\%$$

Calculations for Maximum Control Method Effectiveness

Several factors contribute to the sulfur dioxide reduction potential of the three control methods, including: 1) the uncontrolled sulfur dioxide emission rates from burning greater than 3 percent sulfur coal and greater than 2 percent sulfur coal; 2) the volume of coal use to be controlled; and 3) the effectiveness of each control method in controlling sulfur dioxide. We have estimated the uncontrolled emission rates from greater than 3 percent and greater than 2 percent sulfur coal as follows:

$$SO_2 \text{ emission rate} = \frac{S \times EF}{W}$$

Where: S = percent sulfur content per ton of coal
EF = emission factor: pounds SO_2 per ton of coal
W = weight conversion factor: pounds per ton

If: S = 3.6% sulfur/ton of > 3% sulfur coal
EF = 38 lb. SO_2/ton of coal
W = 2000 lb. SO_2/ton SO_2

Then: SO_2 emission rate for > 3% sulfur coal = $\frac{0.0684 \text{ ton } SO_2}{\text{ton coal}}$

Similarly, if:

S = 3.1% sulfur/ton of > 2% sulfur coal
(and the values for EF and W are unchanged)

Then: SO_2 emission rate for > 2% sulfur coal = $\frac{0.0589 \text{ ton } SO_2}{\text{ton coal}}$

Next, we assume that all of the high sulfur coal used by utilities in 1980 will be subject to sulfur dioxide controls. Referring back to the table on page 15 of the text, we find that 100 million tons of greater than 3 percent sulfur coal and 200 million tons of greater than 2 percent sulfur coal are consumed annually by utilities nationwide. We can calculate total uncontrolled emissions as follows:

$$(100 \times 10^6 \text{ tons of } > 3\% \text{ sulfur coal}) \times \left(\frac{0.0684 \text{ ton } SO_2}{\text{ton } > 3\% \text{ sulfur coal}}\right) = 6.84 \text{ million tons of } SO_2 \text{ emitted from } > 3\% \text{ sulfur coal/year}$$

and

$$(200 \times 10^6 \text{ tons of } > 2\% \text{ sulfur coal}) \times \left(\frac{0.0589 \text{ ton } SO_2}{\text{ton } > 2\% \text{ sulfur coal}}\right) = 11.8 \text{ million tons of } SO_2 \text{ emitted from } > 2\% \text{ sulfur coal/year}$$

With the coal switching control method, these emissions will essentially be replaced by the emissions from one percent sulfur coal. Using the emission rate formula stated above:

$$SO_2 \text{ emission rate for 1\% sulfur coal} = \frac{0.0190 \text{ ton } SO_2}{\text{ton coal}}$$

Switching all of the greater than 3 percent sulfur coal to one percent sulfur coal potentially could yield total annual emission reductions of:

$$(6.84 \text{ million tons of } SO_2\text{/year}) - [(100 \times 10^6 \text{ tons switched per year}) \times (\frac{0.0190 \text{ ton } SO_2}{(\text{ton 1\% sulfur coal})})] = 4.94 \text{ million tons of } SO_2$$

Switching all of the greater than 2 percent sulfur coal to one percent sulfur coal potentially could yield total annual emission reductions of:

$$(11.8 \text{ million tons of } SO_2\text{/year} - [(201 \times 10^6 \text{ tons switched per year}) \times (\frac{0.0190 \text{ ton } SO_2}{(\text{ton 1\% sulfur coal})})] = 8.00 \text{ million tons of } SO_2$$

With the flue gas desulfurization control method, the uncontrolled emissions will be reduced by 85 percent. Scrubbing the emissions from all coal greater than 3 percent sulfur potentially could yield total annual emission reductions of:

$$(6.84 \text{ million ton of } SO_2 \text{ per year}) \times 0.85 = 5.81 \text{ million tons of } SO_2$$

Scrubbing the emissions from all coal greater than 2 percent sulfur potentially could yield total annual emission reductions of:

$$(11.8 \text{ million tons of } SO_2 \text{ per year}) \times 0.85 = 10.0 \text{ million tons of } SO_2$$

With the coal cleaning control method, the uncontrolled emissions would be reduced by 20 percent. Cleaning all coal greater than 3 percent sulfur potentially could yield total annual emission reductions of:

$$(6.84 \text{ million tons of } SO_2 \text{ per year}) \times 0.20 = 1.37 \text{ million tons of } SO_2$$

Cleaning all coal greater than 2 percent sulfur potentially could yield total annual emission reductions of:

$$(11.8 \text{ million tons of } SO_2 \text{ per year}) \times 0.20 = 2.37 \text{ million tons of } SO_2$$

COMPARISON OF DOE ESTIMATES WITH CONTRACTOR ESTIMATES

The cost estimates plotted on pages 33 and 35 of the report are presented in tabular form on Appendix page 20.

The derivation of the DOE cost estimates has been presented in detail. Key assumptions in the DOE estimates are the real rate of return (5%) and the time horizon (30 years) (see Appendix, page 11-12).

The three contractors use different rates of return and time horizons. Therefore, the same capital (C) and annual costs (A) produce different present value (PV) and annualized costs (AC). In order to minimize such differences, the contractor's summary results have been adjusted to reflect, as far as possible, the DOE economic assumptions.

PEDCO summarizes results in terms of capital and annualized costs. PEDCO does not provide the discount rate or time horizon used to annualize capital costs; their annualization procedure is to divide capital costs by 7, indicating a high discount rate, a short time horizon or some combination of both. Therefore, PEDCO's annualized costs are not used. Rather, the annual costs provided by PEDCO (fuel plus O&M) are combined with their capital cost estimates using the relationship derived on Appendix pages 11-12; i.e., $AC = A + (C \div 15.4)$.

ICF presents annualized costs (in 1980 $) for each of four years: 1985, 1990, 1995 and 2000. ICF has recommended, however, that the 1990 annualized costs be used as most representative of the costs of the strategies analyzed. The present value of the ICF strategies is obtained by multiplying ICF's 1990 annualized costs by 15.4.

TEKNEKRON also provides estimates of Levelized Revenue Requirements (current dollars) over the 20 year period 1980-2000. The present value of this stream of constant annual costs is computed using TEKNEKRON'S real rate of return (5%), inflation rate (8%) and time horizon (20 years). The additional contribution to the present value of costs incurred between 2000 and 2010 must be estimated in order to conform to DOE's 30 year time horizon. This is done by (1) observing the cost trend between 1990 and 2000 reported by TEKNEKRON, (2) assuming the continuation of that trend between 2000 and 2010, (3) computing the present value of that 10 year cost stream, and (4) adding that discounted value to the present value computed from TEKNEKRON'S Levelized Revenue Requirements.

All three contractors employ valid economic procedures; the adjustments to the contractors' summary results are intended only to place all estimates on approximately the same economic footing.

~

SO_2 CONTROL COST COMPARISON TABLE

Source	Strategy [1]	SO_2 Reduced (10^6 tons/yr)	Total Costs Present Value (10^9 \$)	Total Costs Annualized (10^9 \$/yr)	Normalized Costs Present Value (10^9 \$)	Normalized Costs Annualized (10^6 \$/yr)	Scrubbed Capacity (gigawatts)	Coal Affected [3] (10^6 tons/yr)
DOE	SWITCH	4 [2]	8.8 - 19	0.6 - 1.2	2.2 - 4.7	140 - 310	--	67
	FGD	5	15 - 30	1.0 - 2.0	3.0 - 6.0	190 - 390	39	--
	CLEAN	1	3.9 - 6.5	0.3 - 0.4	3.9 - 6.5	250 - 420	--	--
PEDCO	SWITCH	5.9	16.2	1.1	2.8	180	--	176
	FGD 60%	5.2	26.4	1.7	5.1	330	80	--
	FGD 90%	7.8	42.2	2.7	5.4	360	80	--
	CLEAN	1.5	11.9	0.8	7.9	520	--	--
ICF	10% REGIONAL	1.7	2.2	0.1	1.3	84	0.0	18
	10% EACH STATE	1.7	5.6	0.4	3.3	210	0.6	21
	4 LB. CAP	2.7	11.2	0.7	4.2	270	12.4	20
	4 LB. CAP + LCP	2.7	14.9	1.0	5.5	360	13.3	17
	15¢/LB. TAX	6.0	17.1	1.1	2.9	190	7.0	62
	30% REGIONAL	5.1	13.9	0.9	2.7	180	7.3	46
	30% REGION + LCP	5.1	17.8	1.2	3.5	230	9.1	32
	30% EACH STATE	5.1	21.7	1.4	4.3	280	8.6	45
	30% EACH + LCP	6.1	22.6	1.5	4.4	290	11.6	35
	2 LB. CAP	7.0	34.6	2.2	4.9	320	26	67
	2 LB. CAP + LCP	7.0	34.9	2.3	5.0	320	31	46
TEKNEKRON	4 LB. CAP	1.5	4.7	0.3	3.1	200	3.2	16
	4 LB. CAP + LCP	1.5	8.4	0.6	5.6	360	22	10
	2 LB. CAP	5.5	26.5	1.7	4.8	310	41	52
	2 LB. CAP + LCP	5.4	28.6	1.9	5.3	340	55	19
	30% FGD	5.0	22.0	1.4	4.4	290	43	14
	50% FGD	8.2	41.4	2.7	5.1	330	86	11
	CLEAN	1.4	11.5	0.8	8.2	530	-5.0	16

[1] Explanation of the strategies

- The terms "SWITCH," "FGD," and "CLEAN" refer to coal switching, flue gas desulfurization, and coal cleaning, respectively. These terms denote strategies which employ only these methods for reducing SO_2 emissions.
- PEDCO strategies apply only to the 50 powerplants which emit the most SO_2. The "60%" and "90%" designation after FGD refers to the amount of SO_2 reduction at each plant.
- All ICF strategies and the TEKNEKRON "CAP" strategies employ a mixture of SWITCH, FGD, and CLEAN control methods selected on a least-cost basis.
- The ICF "REGIONAL" strategies apply to 31 states east of the Mississippi River. Either 10% or 30% SO_2 emission reduction is obtained from the entire 31 state region at least cost, without regard to the location of emissions within the region.
- "EACH STATE" or "EACH" means that the percent reduction of SO_2 emissions is achieved at least cost within each state. Such strategies affect the 17 western states as well as the 31 eastern states. All costs estimated for the western states have been omitted for comparison purposes because other strategies affect only the eastern states.
- "LCP" means local coal protection. A constraint is placed on the least-cost, regional, or state approach such that 1990 production of high sulfur coal cannot fall below 1985 base case production in any coal supply area.
- "CAP" means an emission rate limitation applied to each powerplant. For example, "4 LB. CAP" means SO_2 emissions may not exceed 4 pounds per million BTU heat input.
- "15¢/LB. TAX" means all powerplants would be charged 15 cents for each pound of SO_2 emissions. Utilities are assumed to respond to such a tax by reducing emissions to the extent possible at less than 15 cents per pound. The costs shown are for emission control only; charges for residual SO_2 emissions are not included.

[2] The DOE SO_2 reductions are half of the theoretical maximums. These are assumptions rather than analytical predictions. The cost estimates follow from the assumed emission reductions.

[3] "Coal Affected" means the reduction in high sulfur coal demand relative to baseline estimates. Increases in low sulfur coal demand are not considered. The purpose is to provide an indication of the potential impact on the high sulfur coal industry, not on overall coal demand.

Question 10: What, in your judgment, are the comparative roles of different source contributors of air pollution as contributing factors in acid precipitation? Would you indicate the sources of such information and whether you agree, or disagree, with such analysis?

Answer: We cannot provide an answer at this time due to the large uncertainties attending current understanding of the phenomenon of acid deposition. There are three types of such uncertainties: (1) the location of resources that may be damaged by current and projected levels of acid deposition; (2) the kinds of emissions that contribute substantially to the acid deposition that is falling or is likely to fall on such sensitive resources (e.g., SO_2, NO_x, VOC/oxidants); and (3) the sources or source areas that appear to contribute substantially to the emissions identified in (2). The current NAPAP research program is designed to provide information that will enable us to reduce or resolve these uncertainties.

However, the point needs to be stated that the ultimate objective of emission reduction is not reduction of acid deposition per se. Damage prevention or reduction is the concern. Identification of the contributions of emission sources to environmental damage depends critically on where or whether damage is likely to occur, how it is caused (e.g., acid, oxidants, other), and the geographic relationship between relevant emissions and susceptible resources.

JAMES A. McCLURE, IDAHO, CHAIRMAN
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D. MICHAEL HARVEY, CHIEF COUNSEL FOR THE MINORITY

United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510

June 13, 1986

The Honorable Donald Bauer
Acting Assistant Secretary for Fossil Energy
Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Acting Assistant Secretary Bauer:

On behalf of the members of the Committee on Energy and Natural Resources, I wish to express our appreciation for your testimony at the Committee's oversight hearings on clean coal technology development and strategies for acid rain control.

Please find enclosed copies of questions submitted to you for response by various members of the Committee. Please note that there are questions to be answered collectively between you and Assistant Secretary Walker, and questions to be answered individually. The joint responses can be sent as a single transmittal from you and Assistant Secretary Walker.

We certainly appreciate your willingness to respond to the enclosed questions in a timely fashion. Please have all responses to us by noon, Wednesday, July 2, and supply the Committee with 40 copies of same. Your responses, and inquiries regarding this request, should be directed to the attention of Richard Grundy, Director of Oversight and Investigation, United States Senate Committee on Energy and Natural Resources, SH-312, Washington, D.C. 20510, telephone (202) 224-2564.

Sincerely,

Jim McClure

James A. McClure
Chairman

Enclosures

JAMES A. McCLURE, IDAHO, CHAIRMAN
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United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510

June 13, 1986

The Honorable Mary L. Walker
Assistant Secretary for Environment, Safety and Health
Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Assistant Secretary Walker:

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Please find enclosed copies of questions submitted to you for response by various members of the Committee. Please note that there are questions to be answered collectively between you and Acting Assistant Secretary Bauer, and questions to be answered individually. The joint responses can be sent as a single transmittal from you and Acting Assistant Secretary Bauer.

We certainly appreciate your willingness to respond to the enclosed questions in a timely fashion. Please have all responses to us by noon, Wednesday, July 2, and supply the Committee with 40 copies of same. Your responses, and inquiries regarding this request, should be directed to the attention of Richard Grundy, Director of Oversight and Investigation, United States Senate Committee on Energy and Natural Resources, SH-312, Washington, D.C. 20510, telephone (202) 224-2564.

Sincerely,

Jim McClure

James A. McClure
Chairman

Enclosures

JOINT QUESTIONS SUBMITTED TO

ASSISTANT SECRETARY MARY WALKER AND ACTING ASSISTANT SECRETARY DONALD BAUER

DEPARTMENT OF ENERGY

HEARINGS ON CLEAN COAL TECHNOLOGY AND ACID RAIN CONTROL

1. Each of you, as representatives of the Administration, has emphasized that the President fully endorses the January 1986 Joint Envoys Report on Acid Rain. However, I am unclear what that endorsement actually represents.

   a. For example, are you saying that the Joint Envoys Report is the Administration's, or more importantly the United States', policy on the need for acid rain mitigation, including schedules for its control?

   b. Does the President's endorsement of the Joint Envoys Report mean the Administration supports a 5-year, $5 billion clean coal technology demonstration program? Would each of you comment.

2. The Envoys Report presents both the United States' and the Canadian positions on the causes of acid rain and the need for its control. In some instances the positions are different. For example, it is the Canadian perception that, unless additional measures (such as the Canadian reduction program) are implemented, the total emission of sulfur oxides affecting Canada will increase. Does the U.S. endorsement of the report mean that the Administration agrees with the Canadian position?

3. The Special Envoys Report recommends establishment of a panel headed by a senior U.S. Cabinet offical to oversee the research demonstration program and select the projects to be co-funded by the Federal government.

   a. Is this panel going to be established? If so, who is the senior U.S. Cabinet offical?

   b. If not, what specific interagency mechanism will be established to implement the Special Envoys Report?

   c. With regard to the DOE Clean Coal Demonstration Program, will DOE make the final selection of proposals? What is going to be the role of the "Panel" referred to in the Special Envoys Report? Or of OMB?

   d. How could the goals of clean coal technology development and acid rain control be better coordinated between EPA and DOE?

4. As Chairman of the authorization Committee for the Clean Coal Technology program and the Interagency Taskforce on Acid Rain Research, I request that each of you keep this Committee fully and completely informed of progress in these areas.

5. a. In your opinions, what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the

extension of the life of existing facilities rather than their retirement and replacement with new facilities?

b. Under what circumstances will life-extension result in reduced atmospheric emissions?

c. In your judgements, should utilities be permitted to shift to imported oil to comply with acid rain controls?

6. There has been considerable mention of the need to place emphasis on the development of clean coal technologies with retrofit application.

The Special Envoys Report also emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

a. In your judgements, does the DOE Clean Coal Technology program adequately reflect this need? Or does the program place too much priority on technologies applicable to new construction?

b. Conversely, do these statements in the Envoys Report suggest that it is the Administration's judgement that the DOE Clean Coal Technology Program should be limited to retrofit technologies?

c. Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control? Should they be?

7. Are the technologies being developed by the DOE clean coal technology program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?

8. What is the national average cost of FGD retrofit per kilowatt? And, what would be the aggregate cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements? What would be the differential cost between implementation of the above two options?

9. What, in your judgement, are the estimated costs of implementing proposed acid rain legislation? Would you indicate the sources of such cost estimates and whether you agree, or disagree, with such analysis?

10. What, in your judgement, are the comparative roles of different source contributors of air pollution as contributing factors in acid precipitation? Would you indicate the sources of such information and whether you agree, or disagree, with such analysis?

QUESTIONS SUBMITTED TO ACTING ASSISTANT SECRETARY DONALD BAUER

11. The DOE budget documents do not identify acid rain control as an objective of the Clean Coal Technology program. Why?

12. In testimony before the House Commerce Subcommittee on Health and Environment, Secretary Herrington cast doubt on whether the Administration intends to seek additional funds for clean coal technology development. Would you comment in light of the Administration's endorsement of the Joint Envoys Report?

13. Your prepared testimony states that DOE has completed the preliminary evaluation of the clean coal technologies and has determined that 39 proposals will proceed to comprehensive evaluation.

    a. In your judgement do these proposals emphasize new construction applications? In your judgement do the proposals have retrofit applications?

    b. In your judgement, under current law do you have the authority to give preference to proposals for retrofit applications as recommended in the Envoys Report? Or should you?

14. Your prepared testimony states that performance testing of these projects generally will not be completed until the early to mid-1990s. You conclude with the observation that"if the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options".

    a. If this were to occur, in your judgement, which, if any, of the technologies under evaluation by the DOE Clean Coal Technologies Program, whether assisted by DOE or not, are likely to be utilized to comply with the acid rain control deadlines being proposed?

    b. What improvements in the costs of compliance with emission controls can be foreseen from clean coal technologies?

ADDITIONAL QUESTIONS FOR ACTING ASSISTANT SECRETARY BAUER
FROM SENATOR FORD

15. After the selection, by August 1, 1986, of projects submitted in response to the Clean Coal Program Opportunity Notice, what happens if one of the winners drops out during the subsequent negotiations in the fall? Will you award the remaining funds to the next highest priority project on the selection list?

16. How many different technologies were represented among the responses to the PON?

17. How many of these proposed technologies are retrofit technologies?

18. How many of the project proposals the Department received were for the demonstration of retrofit technologies?

QUESTIONS FROM SENATOR BILL BRADLEY

Questions for Donald Bauer, Acting Assistant Secretary for Fossil Energy

19. In a lot of ways, the clean-coal program ressembles the recently disbanded Synthetic Fuels Program. These federal dollars are going to "push the market." If the Synfuels Program is any example, the federal government seems to be a poor sponsor of nearly commercial technologies. What is being done to assure a different outcome for the clean-coal program than the Synfuels program?

QUESTIONS SUBMITTED TO ASSISTANT SECRETARY MARY WALKER

11. On page 4 of your prepared testimony you cite three recent Federal initiatives to expand or add programs to stimulate technology for clean coal innovation: first, the DOE core fossil energy R & D program; second, the clean coal technologies demonstration program; and, third, the Special Envoys Report. The Administration was rather adamant in its opposition to Congressional funding for many of these DOE programs. Is the Administration now prepared to support these programs, or is the Congress faced with further proposed deferrals of funds?

12. On page 1 of your prepared testimony you state that, "the Administration will act when it is reasonably certain that action will achieve intended results and these results justify the social and economic costs". Your statement suggests the performance of some type of cost-benefit analysis. This appears inconsistent with the statement of other witnesses that the objective of the Federal program is to seek more cost-effective means for acid rain control. Your statement suggests that unless intended results can be justified on the basis of some yet to be determined social and economic benefits, then the Administration is not going to be prepared to recommend any form of control of acid rain. Would you clarify your statement in this regard?

13. As Assistant Secretary for Environment, Health, and Safety, what research is DOE conducting on the causes and effects of acid rain?

14. Your statement comments on the social and economic costs associated with implementing control programs similar to those in various bills. Would you comment further?

    a. Are your comments based on analyses undertaken by your office, or the Department, or others?

    b. What analysis has your office, or the Department, undertaken on the effects of various legislative proposals on, for example,

        i. increased oil imports as a consequence of fuel switching?

        ii. regional losses of coal production, as a consequence of fuel switching to either low sulfur coal or natural gas or oil?

        iii. regional increases in coal production?

        iv. Has the Department evaluated the studies that have been undertaken by others? If not, why not?

        v. Is this work being undertaken in-house or under contract? If under contract, by whom?

15. Your statement estimates that even without new clean air legislation by 1997 there will be a decrease in demand for higher sulfur coal ranging up to 100 million tons per year with similar increases in demand for lower sulfur coal. However, it is unclear whether you are saying that this shift will occur within Northern

Appalachia and the Midwest coal areas, or whether this shift will occur between East and Western coal areas. Would you comment?

But, more importantly, what is your estimate of the effect of the various legislative proposals in this regard?

SET II

POST-HEARING QUESTIONS AND ANSWERS

relating to the

JUNE 9, 1986, HEARING

before the

COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

WITNESS: DONALD L. BAUER
ACTING ASSISTANT SECRETARY FOR FOSSIL ENERGY
DEPARTMENT OF ENERGY

QUESTIONS 11 THROUGH 19

QUESTIONS FROM CHAIRMAN MCCLURE

Question 11:	The DOE budget documents do not identify acid rain control as an objective of the Clean Coal Technology program. Why?
Answer:	According to Congressional guidance, the Clean Coal Technology Program is open to all clean coal technologies, all market applications and all U.S. mined coals. Accordingly, the program includes all acid rain controls, but also includes a broader range of clean-use issues.

Question 12: In testimony before the House Commerce Subcommittee on Health and Environment, Secretary Herrington cast doubt on whether the Administration intends to seek additional funds for clean coal technology development. Would you comment in light of the Administration's endorsement of the Joint Envoys Report?

Answer: There are a number of ongoing and planned activities in both government and industry which we believe can lead to the fashioning of appropriate mechanisms for implementing the Special Envoys' Report. We will rely heavily upon the information developed as part of these programs. The Clean Coal Technology Program (CCTP), of at least $800 million ($400 million govt. share), currently being conducted by DOE as directed by Congress is one of those key activities. Others include EPA's solicitation for another Limestone Injection Multistage Burner (LIMB) demonstration project; the clean coal demonstration program being solicited by the State of Ohio, involving $100 million of State funds plus industry cost-sharing; a multi-faceted clean coal effort by the State of Illinois; and numerous industry-sponsored projects. The Administration is encouraging other States to undertake similar efforts.

The information from these ongoing programs will be an important factor in determining the most appropriate and cost-effective future steps in implementing the initiative proposed by the Joint Envoys.

Question 13: Your prepared testimony states that DOE has completed the preliminary evaluation of the clean coal technologies and has determined that 39 proposals will proceed to comprehensive evaluation.

a: In your judgment, do these proposals emphasize new construction applications? In your judgment, do the proposals have retrofit applications?

Answer: Based on information contained in the public abstracts, we have conducted an analysis of the number of proposals versus application (see Attachment 1). From Attachment 1, it can be seen that retrofit applications are well represented with 16 proposals for retrofit hardware, plus 15 for pre-combustion fuel cleaning, which can be seen as a retrofit applicable to any plant.

b: In your judgment, under current law do you have the authority to give preference to proposals for retrofit applications as recommended in the Envoys' Report? Or should you?

Answer: The selection of projects under the Clean Coal Technology Program will be made by applying the evaluation criteria and program policy factors that were established in the Program Opportunity Notice of February 17, 1986.

Attachment 1

CLEAN COAL TECHNOLOGY DEVELOPMENT

STATISTICS BY USER APPLICATION

User Application	Number of Proposals
Electric Utility (New)	4
Electric Utility (Retrofit)	12
Fuel Processing/Formation (applies to new and retrofit plants)	15
Flue Gas Cleanup Retrofit	4
Iron and Steel	2
Other Industrial/Steam	8
Other	1
Not Identified	5
TOTAL	51

Question 14: Your prepared testimony states that performance testing of these projects generally will not be completed until the early to mid-1990s. You conclude with the observation that "if the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options".

a: If this were to occur, in your judgment, which, if any, of the technologies under evaluation by the DOE Clean Coal Technologies Program, whether assisted by DOE or not, are likely to be utilized to comply with the acid rain control deadlines being proposed?

Answer: In order to protect fully the integrity of the process by which we evaluate and select proposals, based on full and open competition, no information on the proposals can be disclosed prior to selection, other than the information provided by the proposers in the public abstracts. Therefore, we are not able to respond at this time.

b: What improvements in the costs of compliance with emission controls can be foreseen from clean coal technologies?

Answer: Although we cannot respond to this question based on information contained in any of the proposals, Attachment 2 contains estimates of control costs for technologies that are commercially available and under development. The information contained in Attachment 2 is based upon data developed by DOE.

ATTACHMENT 2

POTENTIAL PERFORMANCE OF ACID RAIN CONTROL TECHNOLOGIES

TECHNOLOGY	EMISSIONS REDUCTION (%) SO_x	NO_x	INCREMENTAL COST (MILLS/KWHR)	$/TON SO_2	MATURITY
LIMESTONE SCRUBBER	90-95	NEG.	13-20	600-950	AVAILABLE
DRY SCRUBBER	70	NEG.	10-12	780-1080	AVAILABLE
LIMESTONE INJECTED[1/] MODIFIED BURNER (LIMB)	30-60	40-50	1-9	215-1390	COMMERCIAL EARLY 90s
ADVANCED SO_x/ NO_x CLEANUP DEVICES	90-95	90-95	6-10	270-610	COMMERCIAL EARLY 90s
CONVENTIONAL PHYSICAL COAL CLEANING	33-50	NEG.	2-5	250-720	AVAILABLE
ADVANCED PHYSICAL COAL CLEANING	60-65	NEG.	4-7	270-450	COMMERCIAL LATE 80s
PHYSICAL AND CHEMICAL COAL CLEANING	90-94	NEG.	13-20	600-950	COMMERCIAL EARLY 90s
PRESSURIZED FLUIDIZED BED COMBUSTION RETROFIT	90-98	75-85	10[2/]	420-460	COMMERCIAL MID 90s
ATMOSPHERIC FLUIDIZED BED COMBUSTION RETROFIT	90-95	50-75	12	520-560	COMMERCIAL EARLY 90s

1/ EPA FUNDED.

2/ DOES NOT INCLUDE THE BENEFITS OF LOWER COST ADDITIONAL CAPACITY.

QUESTIONS FROM SENATOR WENDELL FORD

Question 15: After the selection, by August 1, 1986, of projects submitted in response to the Clean Coal Program Opportunity Notice, what happens if one of the winners drops out during the subsequent negotiations in the fall? Will you award the remaining funds to the next highest priority project on the selection list?

Answer: If a project(s) selected drops out for any reason, then we will apply the evaluation criteria and program policy factors to the remaining proposals to select an additional project or projects up to the level of available Federal funds.

QUESTIONS FROM SENATOR WENDELL FORD

Question 16: How many different technologies were represented among the responses to the PON?

Answer: Attachment 3 was prepared on the basis of information provided in the public abstracts prepared by the project sponsor and submitted, at DOE's request, as part of the proposal.

Attachment 3

CLEAN COAL TECHNOLOGY DEVELOPMENT

STATISTICS BY TECHNOLOGY CATEGORY

User Application	Number of Proposals
Surface Coal Gasification	9
Post-Combustion Cleanup	5
Coal Preparation	9
Industrial Processes	3
Underground Coal Gasification	1
Advanced Combustion	4
Coal Liquefaction	3
Atmospheric Fluidized Bed Combustion	7
Pressurized Fluidized Bed Combustion	2
Fuel Cells	2
Not Identified	6
TOTAL	51

QUESTIONS FROM SENATOR WENDELL FORD

Questions 17 & 18: How many of these proposed technologies are retrofit technologies? How many of the project proposals the Department received were for the demonstration of retrofit technologies?

Answer: Most technologies can be used in new or retrofit applications. The actual choice of technology in any given case would depend on the specific project objectives and applications, including site related, regulatory, and environmental factors and source of fuel. Therefore, any attempt to categorize the technologies as "new" or "retrofit" would not, in our opinion, be meaningful. However, Attachment 1 which was prepared based on information provided in the public abstracts, shows that about one-third of the proposals received were for retrofit hardware demonstration projects. In addition, almost another third were for pre-combustion fuel cleaning technologies, which are analagous to retrofits and which are applicable to all plants.

QUESTIONS FROM SENATOR BILL BRADLEY

Question 19:	In a lot of ways, the Clean Coal Program resembles the recently disbanded Synthetic Fuels Program. These federal dollars are going to "push the market". If the Synfuels Program is any example, the Federal Government seems to be a poor sponsor of nearly commercial technologies. What is being done to assure a different outcome for the Clean Coal Program than the Synfuels Program?
Answer:	The Clean Coal Technology Program (CCT) consists of a solicitation to conduct cost-shared clean coal technology projects to demonstrate the feasibility of these technologies for future commercial applications. Your interpretation of history is one that the Administration has often agreed with, and it was brought up several times in the discussions preceding the enactment of P. L. 99-190. We intend, however, to learn from experience since the Clean Coal Technology program has been mandated. P. L. No. 99-190 and the guidance provided in its legislative history played a critical role in the development of the qualification and evaluation criteria established in the Program Opportunity Notice (PON). In particular, we believe that cost-sharing requirements of the PON will help ensure the receipt of proposals for projects with a higher probability of success. The PON also contains evaluation criteria which address the projected commercialization of the proposed demonstration projects. Finally, the CCT projects will be industry projects assisted by the Government. Their commercial viability depends not only on the outcome of the demonstration projects but on the willingness of buyers in the marketplace to utilize them in commercial applications.

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D. MICHAEL HARVEY, CHIEF COUNSEL FOR THE MINORITY

United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510

June 13, 1986

The Honorable Donald Bauer
Acting Assistant Secretary for Fossil Energy
Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Acting Assistant Secretary Bauer:

On behalf of the members of the Committee on Energy and Natural Resources, I wish to express our appreciation for your testimony at the Committee's oversight hearings on clean coal technology development and strategies for acid rain control.

Please find enclosed copies of questions submitted to you for response by various members of the Committee. Please note that there are questions to be answered collectively between you and Assistant Secretary Walker, and questions to be answered individually. The joint responses can be sent as a single transmittal from you and Assistant Secretary Walker.

We certainly appreciate your willingness to respond to the enclosed questions in a timely fashion. Please have all responses to us by noon, Wednesday, July 2, and supply the Committee with 40 copies of same. Your responses, and inquiries regarding this request, should be directed to the attention of Richard Grundy, Director of Oversight and Investigation, United States Senate Committee on Energy and Natural Resources, SH-312, Washington, D.C. 20510, telephone (202) 224-2564.

Sincerely,

Jim McClure

James A. McClure
Chairman

Enclosures

QUESTIONS SUBMITTED TO ACTING ASSISTANT SECRETARY DONALD BAUER

11. The DOE budget documents do not identify acid rain control as an objective of the Clean Coal Technology program. Why?

12. In testimony before the House Commerce Subcommittee on Health and Environment, Secretary Herrington cast doubt on whether the Administration intends to seek additional funds for clean coal technology development. Would you comment in light of the Administration's endorsement of the Joint Envoys Report?

13. Your prepared testimony states that DOE has completed the preliminary evaluation of the clean coal technologies and has determined that 39 proposals will proceed to comprehensive evaluation.

    a. In your judgement do these proposals emphasize new construction applications? In your judgement do the proposals have retrofit applications?

    b. In your judgement, under current law do you have the authority to give preference to proposals for retrofit applications as recommended in the Envoys Report? Or should you?

14. Your prepared testimony states that performance testing of these projects generally will not be completed until the early to mid-1990s. You conclude with the observation that"if the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options".

    a. If this were to occur, in your judgement, which, if any, of the technologies under evaluation by the DOE Clean Coal Technologies Program, whether assisted by DOE or not, are likely to be utilized to comply with the acid rain control deadlines being proposed?

    b. What improvements in the costs of compliance with emission controls can be foreseen from clean coal technologies?

ADDITIONAL QUESTIONS FOR ACTING ASSISTANT SECRETARY BAUER
FROM SENATOR FORD

15 . After the selection, by August 1, 1986, of projects submitted in response to the Clean Coal Program Opportunity Notice, what happens if one of the winners drops out during the subsequent negotiations in the fall? Will you award the remaining funds to the next highest priority project on the selection list?

16 . How many different technologies were represented among the responses to the PON?

17 . How many of these proposed technologies are retrofit technologies?

18 . How many of the project proposals the Department received were for the demonstration of retrofit technologies?

QUESTIONS FROM SENATOR BILL BRADLEY

Questions for Donald Bauer, Acting Assistant Secretary for Fosil Energy

19. In a lot of ways, the clean-coal program ressembles the recently disbanded Synthetic Fuels Program. These federal dollars are going to "push the market." If the Synfuels Program is any example, the federal government seems to be a poor sponsor of nearly commercial technologies. What is being done to assure a different outcome for the clean-coal program than the Synfuels program?

SET III

POST-HEARING QUESTIONS AND ANSWERS

relating to the

JUNE 9, 1986, HEARING

before the

COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

WITNESS:

Mary L. Walker
Assistant Secretary
Environment, Safety, and Health
Department of Energy

Questions and Answers Numbers 11 through 15

QUESTIONS SUBMITTED BY SENATOR MCCLURE TO

ASSISTANT SECRETARY MARY WALKER

Question 11:	On page 4 of your prepared testimony you cite three recent Federal initiatives to expand or add programs to stimulate technology for clean coal innovation: first, the DOE core fossil energy R&D program; second, the clean coal technologies demonstration program; and, third, the Special Envoys Report. The Administration was rather adamant in its opposition to Congressional funding for many of these DOE programs. Is the Administration now prepared to support these programs, or is the Congress faced with further proposed deferrals of funds?
Answer:	President Reagan's signing of P.L. 99-190 indicated support for the Clean Coal Technology Program. The President's full acceptance of the Envoys' Report reaffirmed that course of action as appropriate at this time. DOE is fully implementing the Clean Coal Technology Program. We expect no deferral of funds for that program.

Question 12: On page 1 of your prepared testimony you state that, "the Administration will act when it is reasonably certain that action will achieve intended results and these results justify the social and economic costs." Your statement suggests the performance of some type of cost-benefit analysis. This appears inconsistent with the statement of other witnesses that the objective of the Federal program is to seek more cost-effective means for acid rain control. Your statement suggests that unless intended results can be justified on the basis of some yet to be determined social and economic benefits, then the Administration is not going to be prepared to recommend any form of control of acid rain. Would you clarify your statement in this regard?

Answer: I believe all Administration witnesses were consistent in their statements on two parts of the overall Federal program. The DOE Clean Coal Technology Program and the technology program envisioned by the Envoys' Report are designed to stimulate the development of less costly, more efficient technology for control of acid rain precursors. The quoted statement, on the other hand, is taken directly from the U.S. Perspective section of the joint Envoys' report and it relates to the Federal government's effort to determine the need for additional acid rain controls. The quoted statement accurately reflects the principal that a comparison of costs and benefits is relevant to the selection of most new ventures, including additional acid rain controls.

The word "additional" is important. The Clean Air Act currently mandates limitations on the emissions of the principal acid deposition precursors. Those limitations have halted and reversed the rapid increases in sulfur emissions which were occurring in the 1960's. Furthermore, the authorities in the current Act require review and, as necessary, adjustment of current regulations based on new information about health/welfare risk, technology availability, and cost-effectiveness (e.g., the Clean Air Act mandates review cycles of 4 years for NSPS and 5 years for all NAAQS review). Thus, the acid rain control policy question is not whether something should be done, but rather, whether current limitations are adequate, whether, how and when they should be supplemented, and whether current authorities are sufficient to make any changes that are found, on a scientific basis, to be needed.

At present, there are a variety of control alternatives (including continued implementation of the current Clean Air Act) which can be considered, but there is presently insufficient scientific information on adverse effects and effects prognosis to determine the appropriateness of additional controls.

Because of the current scientific uncertainties, the Administration is not now prepared to recommend whether, how and when current emission controls should be altered. But controls on new facilities are required under existing regulations, and additional retrofit controls might be found necessary by ongoing cause-and-effects research.

Therefore, the development of more cost-effective controls and low emission processes will both facilitate current control programs and provide additional and more cost-effective control options for existing facilities if more stringent emission reductions are determined to be necessary due to the effects of acid deposition.

The Administration has repeatedly stated that we will identify, recommend, support and act on measures found necessary to resolve the acid rain problem when the scientific information is sufficient to decide what measures are appropriate.

It is not expected that the decision will be based solely on a cost-benefit analysis. The difficulties in evaluating ecological damage and risk are substantial. Nevertheless, some comparison of the damage to be reduced or avoided and the costs of such reduction is relevant to such a decision.

Question 13: As Assistant Secretary for Environment, Health, and Safety, what research is DOE conducting on the causes and effects of acid rain?

Answer: The FY 86 budget and the requested FY 87 budget for research into the causes and effects of acid deposition are contained in the attached National Acid Precipitation Assessment Program (NAPAP) Newsletter. The portion of that budget allocated to DOE is shown in the tables by task group.

The former task groups, by function, were:

a. Natural emissions
b. Man-made emissions
c. Atmospheric processes
d. Deposition monitoring
e. Aquatic effects
f . Terrestrial effects
g. Materials effects
h. Control technologies
i. Assessments

The cross-walk between budgets for the former task groups and the newly revised task groups (see pp. 3-4 of Attachment) has not yet been published.

Within DOE, NAPAP participation is divided between my office and the offices of Fossil Energy and Energy Research.

- The Office of the Assistant Secretary for Fossil Energy heads the Man-Made Emissions Task Group. The budget in FY 86 is $700K.
- The Office of the Assistant Secretary for Energy Research is a major contributor to the Atmospheric Processes Task Group ($4,729K), Deposition Monitoring Task Group ($954K), Aquatic Impacts Test Group ($240K), Terrestrial Impacts Test Group ($120K), and Assessment Task Group ($577K).
- My NAPAP budget is $655K. It is used primarily for assessment activities and is supplemented by other DOE funds.

NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM
722 JACKSON PLACE, N.W.
WASHINGTON, D.C. 20506
202/395-5773

NAPAP NEWSLETTER

J. Laurence Kulp, Director of Research

Prepared by the
OFFICE OF THE DIRECTOR OF RESEARCH

March 1986 No. 8

NAPAP FY 1987 BUDGET PRESENTED TO CONGRESS

A FY 1987 NAPAP budget proposal totaling $85.4 million was included in the President's request to Congress in early February. (See table, p. 2.) This budget is roughly level to current 1986 expenditures. While much of the funding is devoted to the continuation of ongoing work, new initiatives planned for 1987 include:

- the addition of volatile organic compounds (VOCs) to both the historic and monthly trends emissions data bases.
- the expansion of the dry deposition monitoring network (15 new sites) to support the needs of effects researchers, modelers, and the National Trends Network.
- the beginning of a pilot study of the Episodic Response Project in the Northeast and Middle Atlantic/Coastal Plain to study the effects of episodic acute changes in surface water chemistry.

Other high-priority programs begun in previous years will also be emphasized. These include:

- continuation of the Terrestrial/Aquatic Linkage Program to evalute the quality of predictions made with the Direct/Delayed Response models.
- continuation of the Forest Response Research Program involving multidisciplinary research cooperatives to study specific forest types -- Spruce Fir, Southern Commercial Pine, Eastern Mixed Hardwoods, and Western Conifers -- to evaluate the potential roles of acidic deposition and associated oxidants in forest decline.
- continuation of the National Surface Water Survey through phases II and III to examine temporal variability and long-term changes in sensitive surface waters.

NAPAP FY 1987 BUDGET REQUEST

TASK GROUP	EPA	USDA	NOAA	DOE	DOI	TVA	TOTAL	%
A			905				905	1.1%
B	3,163			950			4,113	4.8%
C	14,221		2,105	5,015		200	21,541	25.2%
D	6,049	394	1,138	997	2,416		10,994	12.9%
E	18,034	210		250	2,075		20,569	24.1%
F	11,966	9,389		40	1,010	200	22,605	26.5%
G	1,013				1,098		2,111	2.5%
H	323						323	0.4%
I	331			1,950			2,281	2.7%
TOTALS:	55,100	9,993	4,148	9,202	6,599	400	$85,442	
	64.5%	11.7%	4.9%	10.8%	7.7%	0.5%		100.0%

ODR STAFF ADDITIONS

Michelle Nuttall joined the Office of the Director of Research in early February as a technical editor. At present her duties include production of the 1985 Annual Report, and assisting in the details of the Materials Review Workshop. A native Californian, Michelle is one of the few people in the office enthusiastic about the snow.

Dr. Patricia Irving of Argonne National Laboratory will begin working in the ODR this spring. She will be responsible for the planning and management of NAPAP's crops effects research effort.

Dr. Jack Winjum, currently with the Weyerhaueser Corp. in Seattle, will be working in the ODR as a technical expert in the near future. Dr. Winjum will help direct the terrestrial effects program under NAPAP. We hope you all join us in welcoming Michelle, Pat, and Jack aboard!

NEW NAPAP PHONE NUMBER

With the expansion of phone services at the Office of the Director of Research, the new phone number for the main line to NAPAP has been changed to 202/ 395-5771. Please use this new number when calling NAPAP.

NAPAP ORGANIZATION CHANGES

Dr. J. Laurence Kulp, Director of Research, has announced a new struture of the NAPAP task groups to enhance the oversight and management of the various research areas. The task group and subgroup leaders are responsible for the formulation of the scientific program with the participation of the members of the task group (see table, p. 4). The program is reviewed with the Director of Research and the relevant members of the Interagency Science Committee (ISC, formerly Executive Committee) prior to submission by the director to the Joint Chairs for final adoption.

The ISC, which is chaired by the Director of Research and consists of seven technical executives of the agencies to provide liaison and advice to the Director, has had several recent changes in personnel. Dr. Jack Pickering has replaced Mr. Wayne Marchant as the DOI representative, Dr. Charlie Philpot of USFS has replaced Dr. Keith Shea, who retired Feb. 28, and Dr. Myron Iwanski will represent the Tennessee Valley Authority as an observer on the ISC.

The former Interagency Assessment Advisory Committee has also been restructured, as the Interagency Policy Committee (IPC). Its members include policy representatives from the supporting agencies, as well as the Director of Research. It is chaired by the EPA representative. Current membership lists for both the ISC and IPC are given on p. 5.

The responsibility for producing the interim and final assessments of the NAPAP lies with the Office of the Director of Research (formerly the Program Coordination Office). The former Assessments Task Group (I) has been abolished. The functions of the previous Task Group J, International Activities, will be the responsibility of the ODR, supported by the International Activities Working Group, chaired by Mr. Robert Coe of the Dept. of State. The new task groups, their scope, and leadership are as follows:

March 1986 [illegible] No. 8

Task Group	Subject Areas	Task Group Leaders Sub-task Group Leaders	Lead Agency
I	Emissions and Controls	David Beecy	DOE
	- Emissions Inventories	David Mobley, EPA	
	Emissions Prediction	Ed Trexler, DOE	
	Control Technologies	Frank Princiotta, EPA	
II	Atmospheric Chemistry	Daniel Albritton and J. Laurence Kulp	NOAA
	Natural Sources	Daniel Albritton, NOAA	
	Clear Air	Fred Fehsenfeld, NOAA	
	Clouds and Scavenging	Jeremy Hales, PNL	
	Dry Deposition	Bruce Hicks, NOAA	
	Mtn. Cloud Environment	Volker Mohnen, SUNY/Albany	
III	Atmospheric Transport	Chandrakant Bhumralkar and Robin Dennis	NOAA
	Global Background		
	Mesoscale Analysis		
	RADM Development		
	Validation of Models		
IV	Atmospheric Deposition and Air Quality	Paul Kapinos	DOI
	NTN Operations		
	Ambient Air Quality		
	Supplementary Networks		
	Data Management & Analysis		
	Deposition Research Stations		
V	Terrestrial Effects	David Radloff	USDA
	Agricultural Crops		
	Unmanaged Soil		
	Tree Plantations		
	Natural Forests		
	High Elevation Forests		
VI	Aquatic Effects	Rick Linthurst	EPA
	Status - Surveys		
	Prediction - Direct Delayed		
	Validation - Watershed Manipulation		
	- Long Term Monitoring		
	Aquatic Biology		
VII	Materials Effects	Dave Flinn	DOI
	Cultural		
	Construction		

NAPAP Committee Memberships

Agency	Interagency Science Committee	Interagency Policy Committee
ODR	Dr. J. L. Kulp (chair)	Dr. J. L. Kulp (*ex officio*)
NOAA	Dr. Lester Machta	Mr. J. R. Spradley
EPA	Dr. Courtney Riordan	Mr. Dwain Winters
USDA	Dr. Charles Philpot	Dr. Melvin Cotner
DOE	Dr. George Jordy	Mr. Ted Williams
DOI	Dr. R. J. Pickering	Mr. Martin Smith
DOS	Mr. Robert Coe	Mr. Robert Coe
CEQ	-------	Ms. Jacqueline Sachafer

[Observers and alternates not listed]

1985 ANNUAL REPORT UNDERWAY

A release date of June 30 is planned for this year's Annual Report. The first review is well underway, and the assistance of agency leads in compiling reviewer suggestions is expected to prove key to this year's streamlined production schedule. Agency leads are Dave Radloff, USDA; Walt Warnick, DOE; Jack Pickering, DOI; Gary Foley, EPA; and Rick Artz, NOAA. The primary goal of this year's report is to increase content comprehension by novice readers. Task Group chapters will now be organized by project rather than in categories of past, present, and future activities, making it easier to track the progress of each project. An increase in the number and quality of graphs, tables, charts, and figures is also expected to improve readability.

UPCOMING NAPAP WORKSHOPS

A workshop on dry deposition research and information needs within NAPAP and elsewhere will be held March 25-27, 1986 in Harper's Ferry, WV. Working groups will discuss areas of current information gaps and possible remedies. The meeting is by invitation only; availability of the meeting report will be announced in a future Newsletter.

A NAPAP workshop to finalize requirements for the 1985 emissions inventory will be held in Washington, DC April 3-4, 1986. Invited participants, representing both producers and users of emissions information, will discuss information requirements and resources in the development of the 1985 inventory.

-(cont'd...)

A review of the research being carried out by the Materials Effects Task Group (TG VII) is scheduled for the week of April 7 in Raleigh, NC. Outside expert panels on Paint/Metal Damage Functions, Stone Damage Functions, Cultural Resources Inventory, Construction Inventory, and Economics will review projects being carried out by the task group and make suggestions for improvements in protocol, quality assurance, task group orientation and the direction of future research. The workshop is expected to provide many helpful suggestions in planning future task group projects. For further information contact Janet McFayden at North Carolina State University (919/737-3520).

A crop research workshop will be held in Chicago, IL April 17-18, 1986. The workshop is designed to assess the current state of knowledge about the effects on crops from acid precipitation and oxidants acting alone or in combination. Invited workshop participants will address perceived gaps in our scientific knowledge and recommend directions of any further research.

REVISED NAPAP FY 1986 BUDGET

A number of changes have occured in the 1986 NAPAP budget, including internal agency reprogrammings, Congressional appropriations, and other reallocations. These new figures also reflect the incorporation of reductions required by the Gramm-Rudman-Hollings Act.

NAPAP FY 1986 BUDGET ($ K)

		USDA					DOI					
TASK GROUP	EPA	CSRS	ARS	FS	NOAA	DOE	NPS	USGS	FWS	BLM	TOTAL	%
A					832						832	1.0%
B	3,363					700					4,063	5.0%
C	8,590				2,086	4,729					15,405	18.8%
D	5,760	248		146	1,138	954	111	1,923		85	10,365	12.6%
E	18,034			210		240	374	420	1,494		20,772	25.3%
F	11,758	1,045	384	10,849		120		500			24,656	30.1%
G	1,013						825	155			1,993	2.4%
H	623										623	0.8%
I	2,065					1,232					3,297	4.0%
		1,293	384	11,205			1,310	2,998	1,494	85		
TOTALS:	51,206		12,882		4,056	7,975		5,887			$82,006	
	62.4%		15.7%		4.9%	9.7%		7.2%			100.0%	

SCHEDULE OF NAPAP ACTIVITIES

March - May 1986

Date	Group/Meeting	Purpose/Contact	Location
MARCH			
6	Interagency Science Committee		Washington
10	Task Group Leaders		Washington
12	Interagency Policy Committee		Washington
18	Fed./State/Private Sector Steering Comm.	Planning for November research coord. workshop (Bob Downing, 202/ 395-5771)	Washington
25-27	Dry Deposition Workshop	Bruce Hicks, NOAA 615/ 574-1232	Harper's Ferry, WV
APRIL			
3-4	Emissions Inventory Workshop	To finalize plans for the 1985 emissions inventory	DOC, Washington
7-9	Materials Peer Review	To assess the status of the NAPAP effects on materials research program	Research Triangle Pk, NC
21	Joint Chairs Council		Washington
28-May 2	Acidification and its Policy Implications	Conference sponsored by the Netherlands government and the UN ECE.	Amsterdam
MAY			
28-29	Watershed Workshop	Paul Ringold, NAPAP (202/ 395-5771)	Boston, MA

N.B.: The 1986 NAPAP Annual Meeting is tentatively scheduled for June 11-12 in the Washington, DC area. Detailed meeting arrangements will be announced when finalized.

For more information, submission of items to be included in the next Newsletter, or to be put on the mailing list, please contact Bob Downing at 722 Jackson Place NW, Washington, DC 20506.

Question 14: Your statement comments on the social and economic costs associated with implementing control programs similar to those in various bills. Would you comment further?

a. Are your comments based on analyses undertaken by your office, or the Department, or others?

b. What analysis has your office, or the Department, undertaken on the effects of various legislative proposals on, for example,

i. increased oil imports as a consequence of fuel switching?

ii. regional losses of coal production, as a consequence of fuel switching to either low sulfur coal or natural gas or oil?

iii. regional increases in coal production?

iv. Has the Department evaluated the studies that have been undertaken by others? If not, why not?

v. Is this work being undertaken in-house or under contract? If under contract, by whom?

Answers: a. Our comments are based on analyses performed by Argonne National Laboratory (ANL) for the Department of Energy, by ICF Inc. for the Environmental Protection Agency, earlier studies by ICF for DOE, and in-house analyses.

b.i. There is no quantitative information available. An analytical approach is being developed by ANL. We hope to have results from that effort by late summer.

b.ii. Estimates of regional changes in coal demand due to fuel switching have been made by both Argonne and ICF. See answer to Question 15.

b.iii. Estimates of regional changes in coal demand due to fuel switching have been made by both Argonne and ICF. See answer to Question 15.

b.iv. The Department has evaluated studies by the Office of Technology Assessment; Temple, Barker and Sloane, the Congressional Research Service and ICF Inc.

b.v. Legislative proposals, and analyses of those proposals, are evaluated in-house. We use all available analyses for such evaluation. Our principal contractor for analysis of the recent acid rain proposals is Argonne National Laboratories.

Question 15: Your statement estimates that even without new clean air legislation by 1997 there will be a decrease in demand for higher sulfur coal ranging up to 100 million tons per year with similar increases in demand for lower sulfur coal. However, it is unclear whether you are saying that this shift will occur within Northern Appalachia and the Midwest coal areas, or whether this shift will occur between East and Western coal areas. Would you comment?

But, more importantly, what is your estimate of the effect of the various legislative proposals in this regard?

Answer: Apparently, my statement was not clear. Under current regulations, demand for high sulfur coal is expected to remain approximately constant through the early 1990s and then increase as the building of new coal utilities resumes. The shift in demand from high to low sulfur coal is estimated to occur if an additional SO2 emission reduction of 8-12 million tons were legislated.

A change in demand from high to low sulfur coal would be met by low sulfur coal supplied from both central Appalachia and the West. High sulfur coal supply reductions from levels otherwise predicted would occur in both Northern Appalachia and Midwest production areas.

The estimate I gave in my testimony, which you quote, was based on an analysis by Argonne National

Laboratories (ANL). ANL estimates 84-116 mty coal displaced in North Appalachia and the Midwest. Another estimate, done by ICF Inc. for EPA, projects losses ranging from 77 to 109 million tons per year in those regions.

(Three tables are attached: Table A-4 was done for EPA by ICF Inc. Note that it is a draft and may be changed. The other two tables were done for DOE by Argonne National Laboratories. All three refer to H.R. 4567.)

DRAFT - April 28, 1986

TABLE A-4

COAL PRODUCTION AND SHIPMENT FORECASTS PRELIMINARY ANALYSIS -- 1995

(in millions of tons)

	1980	Base 1995	Changes from Base "Low-Cost"	Changes from Base "Default"
Coal Production				
Northern Appalachia	185.1	197.5	-37.4	-67.4
Central Appalachia	232.8	306.6	+45.5	+72.4
Southern Appalachia	26.4	25.2	+1.8	+4.1
Midwest	134.4	150.5	-33.2	-42.0
West	251.0	515.9	+19.8	+29.0
Total U.S.	829.7	1195.7	-3.4	-4.0
Coal Transportation				
Western Coal Shipped East	36.7	59.0	+15.7	+24.9

Losses from N. Appalachia & midwest	37.4	-67.4
	33.2	42.0
	71.6	109.4

ANL 4/18/86

Method of Achieving Emission Reductions
1997 - State 1.2 Lb/10^6 Btu SO_2 Emissions Cap (Intrastate Trading)

State	Additional FGD Capacity (mw)	Number of Additional FGD's	Shifts in Utility Coal Production Northern Appalachia	Central Appalachia	Southern Appalachia	Midwest	Central West	Great Plains	Rockies
Alabama	0	0	-2.3	-0.6	2.5	0.0	0.0	0.0	0.0
Georgia	0	0	0.0	-6.9	11.9	-4.6	0.0	0.0	0.0
Illinois	1,208	2	0.0	-0.2	0.0	-9.8	0.0	15.7	0.0
Indiana	4,805	11	0.0	7.2	0.0	-8.0	0.0	0.0	-0.9
Iowa	0	0	0.0	0.0	0.0	-1.4	-0.4	3.1	0.0
Kentucky	0	0	0.0	3.1	0.0	-3.0	0.0	0.0	0.0
Maryland	1,112	2	-0.2	0.2	0.0	0.0	0.0	0.0	0.0
Michigan	1,500	2	-1.1	1.9	0.0	-1.0	0.0	0.0	0.0
Mississippi	0	0	0.0	0.0	0.4	0.0	-0.4	0.0	0.0
Missouri	1,445	3	0.0	-0.7	0.0	-4.7	-1.7	9.1	0.0
New Hampshire	337	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ohio	0	0	-24.7	22.6	0.0	-0.3	0.0	-2.5	0.0
Pennsylvania	7,420	11	-0.5	0.0	0.0	0.0	0.0	0.0	0.0
S. Carolina	0	0	0.0	-2.4	2.4	0.0	0.0	0.0	0.0
Tennessee	0	0	0.0	-0.1	8.0	-8.1	0.0	0.0	0.0
W. Virginia	210	1	-8.9	7.8	0.0	0.0	0.0	0.0	0.0
Wisconsin	1,584	3	-4.8	2.8	0.0	-0.8	0.0	6.2	0.0
Total	19,621	36	-42.5	34.7	25.2	-41.7	-2.5	31.6	-0.9

Losses total 101 MTY

Losses from N. Appalachia & Midwest total 84.2 MTY

461.

ANL 4/18/86

Method of Achieving Emission Reductions
1997 - 1.2 Lb/10^6 Btu SO_2 Emissions Cap on All Units (Default Strategy)

State	Additional FGD Capacity (mw)	Number of Additional FGD's	Shifts in Utility Coal Production (10^6 Tons/yr) Northern Appalachia	Central Appalachia	Southern Appalachia	Midwest	Central West	Great Plains	Rockies
Alabama	0	0	-2.54	-0.78	3.52	-0.57	0.00	0.00	0.00
Georgia	0	0	0.00	-10.85	17.29	-6.10	0.00	0.00	0.00
Illinois	1,815	3	0.00	-0.20	0.00	-10.31	0.00	13.40	0.13
Indiana	5,605	13	-0.03	9.68	0.00	-11.05	0.00	0.00	-0.97
Iowa	0	0	0.00	0.00	0.00	-1.58	-0.74	3.18	-0.05
Kentucky	1,110	2	0.00	6.20	0.00	-6.59	0.00	0.00	0.00
Maryland	1,112	2	-3.98	3.71	0.00	0.00	0.00	0.00	0.00
Michigan	3,748	5	-1.32	1.79	0.00	-1.11	0.00	-1.10	0.97
Mississippi	0	0	0.00	0.00	0.65	-0.68	0.00	0.00	0.00
Missouri	1,445	3	0.00	-0.57	0.00	-8.14	-2.23	14.50	0.00
New Hampshire	337	1	-0.30	0.30	0.00	0.00	0.00	0.00	0.00
Ohio	0	0	-27.92	25.22	0.00	-1.05	0.00	-2.51	0.00
Pennsylvania	11,047	20	-4.66	4.53	0.00	0.00	0.00	0.11	0.00
S. Carolina	280	1	0.0	-5.93	6.00	0.00	0.00	0.00	0.00
Tennessee	905	1	0.0	-6.26	16.72	-10.78	0.00	0.00	0.00
W. Virginia	0	0	-12.29	9.88	0.00	0.00	0.00	0.00	0.00
Wisconsin	674	2	-3.11	0.00	0.00	-2.24	0.00	8.60	0.01
Total	28,078	53	-56.15	36.72	44.18	-60.20	-2.97	36.18	0.11

Losses total 149 MTY

Losses from N. Appalachia & Midwest total 116.4 MTY

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United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510

June 13, 1986

The Honorable Mary L. Walker
Assistant Secretary for Environment, Safety and Health
Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Assistant Secretary Walker:

On behalf of the members of the Committee on Energy and Natural Resources, I wish to express our appreciation for your testimony at the Committee's oversight hearings on clean coal technology development and strategies for acid rain control.

Please find enclosed copies of questions submitted to you for response by various members of the Committee. Please note that there are questions to be answered collectively between you and Acting Assistant Secretary Bauer, and questions to be answered individually. The joint responses can be sent as a single transmittal from you and Acting Assistant Secretary Bauer.

We certainly appreciate your willingness to respond to the enclosed questions in a timely fashion. Please have all responses to us by noon, Wednesday, July 2, and supply the Committee with 40 copies of same. Your responses, and inquiries regarding this request, should be directed to the attention of Richard Grundy, Director of Oversight and Investigation, United States Senate Committee on Energy and Natural Resources, SH-312, Washington, D.C. 20510, telephone (202) 224-2564.

Sincerely,

Jim McClure

James A. McClure
Chairman

Enclosures

QUESTIONS SUBMITTED TO ASSISTANT SECRETARY MARY WALKER

11. On page 4 of your prepared testimony you cite three recent Federal initiatives to expand or add programs to stimulate technology for clean coal innovation: first, the DOE core fossil energy R & D program; second, the clean coal technologies demonstration program; and, third, the Special Envoys Report. The Administration was rather adamant in its opposition to Congressional funding for many of these DOE programs. Is the Administration now prepared to support these programs, or is the Congress faced with further proposed deferrals of funds?

12. On page 1 of your prepared testimony you state that, "the Administration will act when it is reasonably certain that action will achieve intended results and these results justify the social and economic costs". Your statement suggests the performance of some type of cost-benefit analysis. This appears inconsistent with the statement of other witnesses that the objective of the Federal program is to seek more cost-effective means for acid rain control. Your statement suggests that unless intended results can be justified on the basis of some yet to be determined social and economic benefits, then the Administration is not going to be prepared to recommend any form of control of acid rain. Would you clarify your statement in this regard?

13. As Assistant Secretary for Environment, Health, and Safety, what research is DOE conducting on the causes and effects of acid rain?

14. Your statement comments on the social and economic costs associated with implementing control programs similar to those in various bills. Would you comment further?

    a. Are your comments based on analyses undertaken by your office, or the Department, or others?

    b. What analysis has your office, or the Department, undertaken on the effects of various legislative proposals on, for example,

        i. increased oil imports as a consequence of fuel switching?

        ii. regional losses of coal production, as a consequence of fuel switching to either low sulfur coal or natural gas or oil?

        iii. regional increases in coal production?

        iv. Has the Department evaluated the studies that have been undertaken by others? If not, why not?

        v. Is this work being undertaken in-house or under contract? If under contract, by whom?

15. Your statement estimates that even without new clean air legislation by 1997 there will be a decrease in demand for higher sulfur coal ranging up to 100 million tons per year with similar increases in demand for lower sulfur coal. However, it is unclear whether you are saying that this shift will occur within Northern

Appalachia and the Midwest coal areas, or whether this shift will occur between East and Western coal areas. Would you comment?

But, more importantly, what is your estimate of the effect of the various legislative proposals in this regard?

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 29 1986

THE ADMINISTRATOR

Honorable James A. McClure
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

Your letter of June 13, 1986 requested that I respond to a number of questions regarding clean coal technology development and strategies for acid rain control. Enclosed are answers to the questions as numbered in your request.

I apologize for the delay in responding to your questions.

Sincerely,

Lee M. Thomas

Lee M. Thomas

Enclosure

AR-445:OPD:PSchwengels:jr:7/25/86
Control No.: AL-001877
475-8468

Question 1(a) &(b):

Each of you, as representatives of the Administration, has emphasized that the President fully endorses the January 1986 Joint Envoys Report on Acid Rain. However, I am unclear what that endorsement actually represents.

a. For example, are you saying that the Joint Envoys Report is the Administration's, or more importantly the United States' policy on the need for acid rain mitigation, including schedules for its control?

b. Does the President's endorsement of the Joint Envoys Report mean the Administration supports a 5-year, $5 billion clean coal technology demonstration program? Would each of you comment.

Response:

The President fully endorsed the Joint Report of the Special Envoys on Acid Rain and its principal findings and recommendations. There were three findings:

- Acid rain is a serious environmental problem in both the United States and Canada. Acidic emissions transported through the atmosphere undoubtedly are contributing to the acidification of sensitive areas in both countries. The potential for long-term socio-economic costs is high.
- Acid rain is a serious transboundary problem. Air pollutants emitted by sources in both countries cross their mutual border, thus causing a diplomatic as well as an environmental problem.
- At the present time, there are only a limited number of potential avenues for achieving major reductions in acidic air emissions, and they all carry high socio-economic costs.

There were several recommendations in the Report, the first of which was ". . . .the U.S. government should implement a five-year, five-billion-dollar control technology commercial demonstration program. . . ." The Report made no specific recommendations for emissions reductions.

We, along with other federal agencies, are actively working to implement the recommendations of the Special Envoys, as directed by the President.

Question 2:

The Envoys Report presents both the United States' and the Canadian positions on the causes of acid rain and the need for its control. In some instances the positions are different. For example, it is the Canadian perception that, unless additional measures (such as the Canadian reduction program) are implemented, the total emission of sulfur oxides affecting Canada will increase. Does the U.S. endorsement of the report mean that the Administration agrees with the Canadian position?

Response:

In the Report the Envoys described what they believed were the acid rain programs of their respective countries. We have no problem with the description of the U.S. and Canadian programs. This does not mean we agree with all the conclusions implicit in the description of the Canadian program nor they with our program, but we accept these statements as being accurate descriptions of each country's position. This point is highlighted by the Special Envoys in their introduction to the section of the Report on the U.S. and Canadian perspective. The Envoys state:

> "It is not the intent of the Special Envoy process to hide or gloss over the differences in the perceptions and policies of our two countries with respect to acid rain. Quite the contrary. We believe it is important that both the similarities and differences in these perspectives and policies be openly acknowledged and understood. It was not until we had an understanding of the other country's point of view that we were in a position to formulate findings and recommendations. For this reason we have chosen to include in this report the following summaries of the U.S. and Canadian perspectives on acid rain."

With regard to current U.S. acid rain policy we find the following statement made in the U.S. perspective section to be a clear and accurate summary:

> "In the summer and fall of 1983, the U.S. government carried out a thorough review of the current status of acid rain knowledge and the options available for its management. From that review, the United States concluded that, although it was clear that acid

rain was a serious concern both in the United States and Canada, it lacked the information needed to make a prudent decision on the need for or design of additional emission controls."

"This policy was not a decision either for or against additional controls, but instead a choice to defer such a decision until a more adequate scientific and technical base was established. It is not U.S. policy to wait for definitive answers on all major acid rain uncertainties before making a decision to act. Decisions on acid rain, like other environmental decisions, will always have to be made in the face of some scientific uncertainty. The United States is committed to act to control acid rain once it is reasonably certain that the action will achieve its intended results, and those results will justify the social and economic costs entailed."

Question 3(a & b):

The Special Envoys Report recommends establishment of a panel headed by a senior U.S. Cabinet official to oversee the research demonstration program and select the projects to be co-funded by the Federal government.

Is this panel going to be established? If so, who is the senior U.S. Cabinet official?

Response:

Yes, the panel is in the process of being established and the Secretary of Energy will head the panel.

Question 3(c):

With regard to the DOE Clean Coal Demonstration Program, will DOE make the final selection of proposals? What is going to be the role of the "Panel" referred to in the Special Envoys Report? Or of OMB?

Response:

DOE has the legislative authority (P.L. 99-100) and will make the final selection of proposals under the Clean Coal Program by August 1, 1986. EPA has been an advisor on the Clean Coal Source Evaluation Board and has had a member on the subordinate Technical Evaluation Committee. However, EPA representatives do not have any official role on the final selection of proposals.

The panel recommended by the Special Envoys' Report will not participate in the final selection of proposals for the CCT Program being carried out in response to P.L. 99-190. The panel evaluates the results of the CCT Program solicitation under P.L. 99-190, including mandated reports on DOE follow-up activities.

Question 3(d):

How could the goals of clean coal technology development and acid rain control be better coordinated between EPA and DOE?

Response:

Considerable coordination between DOE and EPA on clean coal technology development and acid rain control has been taking place for a long time. DOE and EPA are both active on the Interagency Task Force on Acid Precipitation, the acid rain research coordinating body for Federal agencies. EPA is invited to and does participate in DOE conferences and contractor reviews dealing with research on clean coal technologies, primarily flue gas cleanup and coal preparation systems, being conducted by DOE and its contractors. Likewise, DOE is invited to and does participate in EPA conferences and contractor reviews dealing with research on new environmental technologies applicable to coal utilization. Informal coordination meetings between' representatives of the two agencies, at every technical and management level, occur routinely. In addition, EPA is participating as an environmental advisor and technical evaluator to DOE on the Clean Coal Technology Program, which is currently in the proposal evaluation stage.

Under the recommendations of the Special Envoys Report, EPA and DOE are each given responsibility for providing technical assistance to the "panel." EPA will also be a member of the "panel" chaired by DOE.

Question 4:

As Chairman of the authorization Committee for Clean Coal Technology program and the Interagency Task Force on Acid Rain Research, I request that each of you keep this Committee fully and completely informed of progress in these areas.

Response:

We would be pleased to keep the Committee fully informed of progress in these areas.

Question 5(a):

In your opinions, what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the various legislative proposals before the Congress? For example, is the electric utility industry likely to rely on extension of the life of existing facilities rather than their retirement and replacement with new facilities?

Response:

We expect that the utility industry will extend the life of most large coal-fired boilers regardless of whether or not acid rain legislation goes into effect. However, owners of very small or very old units, if faced with a scrubber retrofit requirement, would probably choose to retire units rather than scrub them. For units that can switch to lower sulfur coal, the owners would be more likely to choose a combination of life extension plus low sulfur coal rather than retirement. Our analysis indicates that, if the least cost approach is adopted by most states, then coal switching rather than scrubbers would be the compliance means of choice.

Question 5(b):

Under what circumstances will life-extension result in reduced atmospheric emissions?

Response:

Normally, life extension alone will not result in reduced emissions. Reductions in emissions would occur only if the life extension is combined with addition of pollution control equipment, a shift to lower sulfur fuel or conversion to fluidized bed combustion.

Question 5(c):

In your judgements, should utilities be permitted to shift to imported oil to comply with acid rain controls?

Response:

Our analyses indicate that very few utilities would shift to imported oil to comply with acid rain controls. This is because this option is generally not cost-effective under most future oil price scenarios.

Question 6:

There has been considerable mention of the need to place emphasis on the development of clean coal technologies with retrofit application.

The Special Envoys Report also emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

a. In your judgements, does the DOE Clean Coal Technology program adequately reflect this need? Or does the program place too much priority on technologies applicable to new construction?

b. Conversely, do these statements in the Envoys Report suggest that it is the Administration's judgement that the DOE Clean Coal Technology Program should be limited to retrofit technologies?

c. Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control? Should they be?

Response:

The Administration has been guided by the Congressional direction that the Clean Coal Technology Program should be open to both new and retrofit applications. This guidance is reflected in the Program Opportunity Notice (PON) issued February 17, 1986.

The Program envisioned in the Special Envoys Report would focus on commercial demonstration of retrofit technologies. It is clear that there is the possibility for overlap between the two programs, and to the extent that that overlap exists, the CCT program provides a head start in implementing the Special Envoys recommendations. Proposals submitted to DOE in response to the PON will be evaluated in accordance with the criteria specified therein. A full understanding of the applicability of the DOE Clean Coal Technology projects to retrofit applications and to acid rain control will become apparent when CCT project selections are made in August.

Question 7:

Are the technologies being developed by the DOE clean coal technology program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?

Response:

New regulatory requirements would not necessarily be needed because many of the technologies submitted are for improving efficiency not for reducing emissions, and they would be used if demonstrated to be cost-effective.

Question 8:

(1) What is the national average cost of FGD retrofit per kilowatt? And, (2) what would be the aggregate cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements? What would be the differential cost between implementation of the above two options?

Response:

We have not analyzed the cost of FGD retrofit on every plant in the country. However, we have looked at the retrofit costs for 120 high-emitting Eastern powerplants. Based upon this analysis, we have concluded that average FGD retrofit capital cost should be about $310/kW in the East. Costs for the West should be lower because most Western plants (1) use low-sulfur coal which is less expensive to scrub and (2) are relatively large and relatively new and therefore relatively easier to retrofit. Thus we estimate that the average retrofit costs for Western powerplants would be about $200/kW. The combined national average would be $280/kW, if the costs we have estimated for the 120 largest emitters are representative of all plants. The range around this average is quite wide; at specific plants retrofit costs could be as low as half and as high as twice the average. Spread over the lifetime of the equipment, the capital costs of FGD retrofits are roughly half the total cost.

The remaining parts of your question deal with retrofit costs versus "emission specific requirements." An emission specific requirement could mean several things: a) a requirement to achieve a certain number of tons of reduction nationwide, such as 4 or 8 or 12 million tons; b) an emission rate cap, such as 1.2 lbs/MMBtu on a statewide average, which can be set equivalent to a tonnage reduction, but has some important differences; or c) a plant-specific or unit-specific emission limit, for example 0.7 lbs/mmbtu or 2.0 lbs/mmbtu.

Unless the tonnage reduction requirement is extremely high or the rate extremely low, such targets can be met by scrubbing, fuel switching, or other approaches, whereas a technology requirement forces a particular compliance strategy. For the same total emission reduction, an emission limit approach will be relatively cheaper for the utility than mandatory scrubbing for two reasons: (1) fuel switching is usually cheaper than scrubbing and (2) some plants are significantly cheaper to scrub than others.

Increased flexibility in the emission limitation approach can also yield savings for the utility. Giving a unit the choice between scrubbing and fuel switching is usually cheaper than forcing it to scrub. Plantwide averaging will be more cost-effective because utilities can choose among the units at the plant and control those at which the reductions would be most cost-effective. Statewide averaging would result in even more savings.

Because of the large differences in retrofit scrubber costs, if utilities are allowed to scrub only the most economical units, the average cost would be much lower than the costs cited above. For Eastern powerplants, the average cost of scrubbing the easier units (56.9% of capacity) is $258/kW as opposed to $378/kW for the more difficult retrofits. Under a "freedom-of-choice" approach a utility would be more likely to retrofit the lower-cost units with FGD, while the difficult retrofits are more likely to be switched to lower-sulfur coal.

$258/kW as opposed to $378/kW for the more difficult retrofits. Under a "freedom-of-choice" approach a utility would be more likely to retrofit the lower-cost units with FGD, while the difficult retrofits are more likely to be switched to lower-sulfur coal.

To illustrate the kinds of savings which might occur under a freedom of choice scenario versus a full scrubbing scenario, we recently examined two options:

(1) a 30-year NSPS case, i.e., once units reached the age of 30, the unit had to install a scrubber. (This is different from S.2203 where plants would have to meet a 0.7 lbs/MMBtu limit by 1995).

(2) a 30-year NSPS case with "bubbling," i.e., units which become "subject" to the NSPS, could obtain their required emission reductions from other plants which had more cost-effective scrubbing or coal switching options.

According to the analysis, the flexibility provided by bubbling saved the utilities $3 billion/year in 1995 ($3.9 billion vs. $0.9 billion)

The estimates in this response focus on the savings to the utilities and do not consider the other social and economic costs of a particular approach.

Question 9:

What, in your judgement, are the estimated costs of implementing proposed acid rain legislation? Would you indicate the sources of such cost estimates and whether you agree, or disagree, with such analysis?

Response:

Costs of acid rain legislation vary widely depending upon the level of the required reduction, the way those reduction requirements are allocated, and the extent to which more expensive scrubbing is mandated instead of coal switching. We are currently in the midst of analyzing H.R. 4567 as reported out by the House Subcommittee on Health and the Environment. Our preliminary analysis indicates that the annualized costs of the bill would range from \$2.8 billion per year to \$7.0 billion per year in the year 2000. The low end of the range represents implementation of the statewide cap of 1.2 lbs/MMBtu of SO_2 and 0.6 lbs/MMBtu of NO_x. The high end represents implementation of the default provision, under which every plant must meet a cap of 1.2 lbs/MMBtu SO_2 and 0.6 lbs/MMBtu NO_x. To derive our cost estimates, we specify assumptions and scenarios for a modelling analysis performed for us by ICF, Inc. The analysis of the revised bill is still underway and should be completed soon.

We have not yet conducted an economic analysis of S.2203. However, based on our general knowledge of acid rain control costs, we would expect this bill to be considerably more expensive than any bill we have analyzed so far. We base this conclusion on our interpretation that implementation of S.2203 would require scrubbing and selective catalytic reduction--or retirement--for every power plant unit.

Question 10:

What, in your judgement, are the comparative roles of different source contributors of air pollution as contributing factors in acid precipitation? Would you indicate the sources of such information and whether you agree, or disagree, with such analysis?

Response:

To judge the comparative contributions of different sources to the acid deposition problem requires knowledge in three areas. First, one needs a detailed understanding of the emissions patterns of SO_2 and NO_x, and volatile organic compounds on a relatively detailed temporal and spatial basis. Second, one needs a modeling capability which can simulate the complex chemical, physical and meteorological processes which enable one to relate rates and patterns of emissions to rates and patterns of deposition. This capability must include the ability to predict both wet and dry deposition of sulfur and nitrogen species. Third, we need to be able to both qualitatively and quantitatively relate these deposition patterns to their consequent effects. The effects component is important because we are only interested in managing emissions for the purpose of reducing deleterious effects. Collectively, these are the major uncertainties which currently prevent administration support of acid rain control legislation.

We currently have some knowledge regarding each of these components. We also have major uncertainties. In our judgement it is the combined effect of these uncertainties, which prevents us from accurately predicting the comparative role of different source contributors to the acid deposition problem. Given these uncertainties, we are forced for analytic purposes to look at emissions contributions either nationally or regionally as a crude approximation of contributions to acid deposition.

The following table indicates the relative contributions to total national emissions of SO_2 and NO_x for major source categories:

	1980 Emissions (millions of tons)	
	SO_2	NO_x
Electric Utilities	17.3	8.1
Industrial Combustion	3.7	4.5
Industrial Processes	4.3	0.9
Mobile Sources	0.9	9.1
Other	0.9	0.5
Total	27.1	23.7

To more accurately discuss the contributions of classes of sources or source regions to deposition in specific sensitive areas, major improvements are needed in the state of the science in the three areas mentioned above. Improving our understanding in these areas are major goals of the NAPAP nemearch effort. I believe that significant improvements will be forthcoming over the next 2-3 years.

Question 11(a):

Administrator Thomas, throughout your prepared statement you emphasize that "the most important application category for the focus of clean coal technology development would be the coalfired retrofit application". This is because of the industry's practice commonly referred to as life-extension.

One of the premises behind the Clean Air Act was that industry would gradually retire old facilities and replace them with new installations subject to "new source performance standards". Consequently, there would be a gradual improvement in air quality.

In your judgement, has this occurred? On page 3 of your prepared statement you comment on plant life extension stating that, "this postpones the rate at which new sources will replace existing sources, making New Source Performance Standards a less effective way of reducing overall emissions in the near or middle term".

Response:

There has been very little retirement of large coal-fired powerplants in the past because most large coal-fired power plants have not yet reached the age at which retirement is even an issue. Thus there is very little historical evidence upon which to base projections of future retirement rates. Our forecast of widespread life extension in the future is based upon our assessment of the overwhelmingly favorable economics of refurbishment relative to building new powerplants. This judgment is reinforced by the significant number of utilities which have announced and/or begun work on life extension programs.

Question 11(b):

Mr. Administrator, to what extent is the decision to extend the life of an existing facility influenced by regulatory policies? For example, at a certain point the costs of retrofitting an existing facility become great enough that it runs the risk of being classified as a new one subject to New Source Performance Standards. Moreover, this percentage, now related to 50 percent of the existing plant's value, is established by regulation, not by law. Would you comment?

Response:

According to our analyses, life extension would be attractive even if the NSPS did not exist. This is because of utilities' (1) expectations of low rates of return on utility capital investments, (2) uncertainty about future load growth, and (3) the high relative cost of new capacity. Environmental requirements are only one contributing factor to the high costs of new plants. Construction and interest costs dominate.

EPA does have some flexibility in defining reconstruction. For example, the 50 percent threshhold could be changed by revising the appropriate regulations. We have no plans to adjust this definition because we believe it would be quite difficult in practice to determine when a plant has spent more than is allowed, particularly if the expenditures are made over a long period of time. Life extension expenditures would normally be made in conjunction with normal maintenance during planned outages and would occur over several years. Any attempt by EPA to tighten down on the 50 percent threshhold would require very detailed and complex regulations and enforcement to determine the precise amount which should be considered capital expenditures for life extension as opposed to other maintenance. To the extent that these regulations were effective, they might well produce otherwise inefficient behavior by industry to avoid the threshhold, rather than reductions in emissions.

Question 11(c):

If you were to reduce this percentage, would the incentive shift from life-extension in favor of new construction?

Response:

Changing the definition of reconstruction would change the economic calculus for the utility. The utility would have the option of either (1) remaining below the new cutoff or (2) comparing the sum of boiler life-extension costs plus scrubber retrofit costs to the costs of alternative power sources.

Our analyses indicate that even under broader NSPS applicability, refurbishment would still be more economically advantageous than capacity additions. However, broadening NSPS applicability could discourage some life extension on the margin, particularly since much of the attractiveness of life extension is due to the fact that it is not capital-intensive and can be done incrementally. Scrubber retrofits, on the other hand, require large capital outlays. However the economics of life extension are generally so compelling that it is possible that a change in the reconstruction definition could result in just as much life extension but with lower emissions and higher costs.

Question 11(d):

Does the fact that you have the authority to do this create a certain regulatory uncertainty for industry?

Response:

It is doubtful that EPA would actually use this authority because of the complexities involved in distinguishing life extension costs from other operation and maintenance costs. Thus, we would guess that if there is any regulatory uncertainty, it is minor relative to the industry's other concerns.

Question 11(e):

What is the potential that the types of clean coal technology under discussion will be able to meet New Source Performance Standards without the use of scrubbers?

Response:

Several of the technologies under discussion would not require scrubbers in order to meet NSPS. The two best examples are fluidized bed combustion and combined cycle gasification.

Question 12:

As Administrator of the Environmental Protection Agency, on the basis of current knowledge of the causes of acid rain, can we formulate a control strategy that will assure achievement of the intended mitigation of acid rain once the prescribed control investments have been made? In other words, can we determine what pollutants need to be controlled, the size reductions that are called for, where the reductions should take place, and over what time frame they should be implemented?

Response:

These are precisely the factors which have prevented me from proposing a solution to the acid rain problem, and as I have stated before this Committee and others, I believe the answers to many of these questions will be forthcoming in the next 2 to 3 years.

Question 13:

In 1980 this Committee authorized the Interagency Task Force on Acid Precipitation, which directs the National Acid Precipitation Assessment Program. In your judgement has that effort significantly advanced our knowledge of the causes and effects of acid rain?

Response:

The National Acid Precipitation Assessment Program has advanced our knowledge of the causes and effects of acid rain considerably over the past several years, but many of the most critical answers will be arriving in 2 to 3 years. In the area of surface water acidification, we have initiated two major research efforts. First, we have implemented a National Surface Water Survey, to help determine the current extent and distribution of acidic surface waters. Second, the Direct/Delayed Response Project will help us to estimate the rate and magnitude of future acidification.

Analysis of Phase I of the Eastern Lake Survey was recently completed and the full report will be distributed soon. Sampling for Phase I of the the Western Lake Survey was completed last fall and analyses are currently in progress. Results of this work are due in December. Additionally, under current schedules, we anticipate that by mid-1987 we will have the results of Phase 1 of the Eastern Stream Survey, and by early 1988, we will have the direct/delayed response estimates for the Northeast and Blue Ridge Province and the results of Phase II of the Eastern Lake Survey.

In the area of forest research, we have established four major research cooperatives, each addressing a different major forest type. These cooperatives are responsible for research and testing of the major hypotheses that attempt to explain forest decline. It is our hope that the preliminary results of FY '88 or '89 research on Eastern Spruce/Fir and Southern Pine forests should be able to provide us with a strong indication of whether or not sulfur deposition is a significant factor in forest decline. A determination of the contributions of other air pollutants (NO_x, O_3, heavy metals) to forest decline should come soon thereafter. Although the initial determinations will be more qualitative than quantitative, knowing whether sulfur or nitrogen have any significant role in forest decline would be a major advancement over our current understanding. Currently, we have no scientifically defensible basis to assume that either sulfur or nitrogen deposition affects forest productivity.

Question 14:

As EPA Administrator, do you believe that it is critical that the U.S. immediately institute acid rain controls and, if not, when would you deem it appropriate for us to begin the formulation of a control strategy for acid rain?

Response:

We believe that policy analysis should be an ongoing process, one that takes and evaluates new scientific knowledge and other factors as they become available. As our uncertainty in this area diminishes, we will reach a point where we can formulate a reasonable response to the acid rain problem. I cannot say in advance when that point will come because I cannot predict the results of our scientific effort. I can, however, estimate when the results of key studies that bear on our ability to make policy choices should be forthcoming. As I said before, several of these studies should be producing results in the next 2 to 3 years.

Question 15:

As you are aware, the Clean Air Act relies on the formulation of State Implementation Plans (SIPs) to determine control requirements on individual sources within a precisely defined air quality control region. By comparison acid precipitation crosses the boundaries between regions. Is our experience in the formulations of SIPs applicable to the formulation of strategies for the control of acid rain? In your judgement how much time would be required for the States to formulate acid rain control plans?

Response:

Some aspects of the experience of EPA and the States with SIPs would be applicable to acid deposition control plans. The process of identifying and assessing possible emission control techniques for various sources or categories of sources should be very similar. Indeed, the knowledge gained of some SO_2 emission control techniques (i.e., flue gase desulfurization) for ambient air quality purposes should be directly applicable to acid deposition control; although the latter would require much more stringent controls on many more sources than the former and may involve some different control techniques such as least emission dispatch or part-year shut-downs.

In other aspects, however, the formulation of acid deposition control strategies would be very different and more difficult than anything EPA or the States have done before. The existing SIP process involves, for the most part, the relatively straightforward application of a commonly accepted set of analytic techniques (short range pollutant dispersion models) to meet an established set of objective standards (the national ambient air quality standards). Few, if any, decisions had to be made which could be percieved as favoring one source of set of sources over another.

In the design of acid deposition plans to meet either a State emission rate or emission ceiling, on the other hand, States will have to allocate control obligations among sources on the basis of consideration which may be neither objective or environmental. The most immediately apparent basis for control allocations might be to minimize the cost of the plan. But this would immediately raise the question, cost to who? Utility stockholder? Ratepayers? Other industries? The State as a whole, taking into account possible impacts on any coal mining or miners within the State? Beyond these relatively quantifiable economic factors would lie considerations such as equity (among industries, interest groups, and geographic regions) and the relative potential of different possible plans to disrupt established employment and communities. Environmental factors such as the effect of different possible plans on ambient air quality or acid sensitive areas within the State may also come into play, but they will have to be weighed along with the above factors because, unlike the SIP process, they will not constitute the primary goal of the plan. In short, the States will have to make public policy choices which they have not had to make before; and they will have to develop and apply new methods to carry out whatever policies are selected.

The development of control plans for the electric utility industry would pose difficult additional problems. The operations of that industry cut across State lines in numerous and complex ways, including multi-state service areas for individual utility companies, multi-utility ownership of individual power plants, and the constant exchange of power among different utilities and States to achieve least cost generation of power to meet demand. Acid rain control plans could affect this system in ways that go beyond an overall increase in costs. For example, differing control obligations (and resulting costs) on different power plants and utility companies would probably change the priority of dispatch among the interconnected plants and utilities, and could shift emissions from one State to another. The control plans of all interconnected States would therefore somehow have to be coordinated. In addition, each control plan would have to be formulated in view of the policies and regulations of the relevant utility rate regulatory bodies, which can drastically affect the effective costs of possible plans to utilities and/or ratepayers.

Although there is great uncertainty as to how these problems would be handled, we believe that these problems could be overcome, and plans could be submitted to EPA, within about 18 months from enactment of an acid rain control law.

Question 16:

Please provide SO_2 emission levels for each State in 1976.

Response:

The attached table provides estimates of SO_2 emissions from both electric utility and other sources for each state in 1976.

1976 SO_2 EMISSIONS
(thousands of tons)

	UTILITY	NON UTILITY	TOTAL
ALABAMA	721.8	309.2	1031.0
ARIZONA	69.8	1461.5	1531.3
ARKANSAS	37.8	58.6	96.4
CALIFORNIA	149.4	445.8	595.2
COLORADO	69.6	70.1	139.7
CONNECTICUIT	24.9	34.6	59.5
DELAWARE	61.7	80.9	142.6
DISTRICT of COLUMBIA	7.0	12.7	19.7
FLORIDA	674.9	409.9	1084.8
GEORGIA	512.9	151.6	664.5
IDAHO	0.0	70.6	70.6
ILLINOIS	1494.6	366.6	1861.2
INDIANA	1481.1	378.0	1859.1
IOWA	215.2	104.1	319.3
KANSAS	127.7	81.7	209.4
KENTUCKY	1552.8	153.8	1706.6
LOUISIANA	32.5	400.3	432.8
MAINE	12.8	140.1	152.9
MARYLAND	220.7	79.6	300.3
MASSACHUSETTS	157.5	99.2	256.7
MICHIGAN	902.6	340.0	1242.6
MINNESOTA	223.4	84.0	307.4
MISSISSIPPI	154.1	187.5	341.6
MISSOURI	1239.6	180.7	1420.3
MONTANA	17.2	225.5	242.7
NEBRASKA	27.7	26.1	53.8
NEVADA	34.4	206.7	241.1
NEW HAMPSHIRE	51.1	30.0	81.1
NEW JERSEY	114.9	231.8	346.7
NEW MEXICO	99.7	275.7	375.4
NEW YORK	513.7	435.8	949.5
NORTH CAROLINA	421.9	235.9	657.8
NORTH DAKOTA	58.7	34.1	92.8
OHIO	2856.0	507.7	3363.7
OKLAHOMA	0.3	67.7	68.0
OREGON	0.0	56.8	56.8
PENNSYLVANIA	1459.9	460.8	1920.7
RHODE ISLAND	3.0	9.7	12.7
SOUTH CAROLINA	165.1	137.5	302.6
SOUTH DAKOTA	33.8	12.3	46.1
TENNESSEE	1261.8	210.9	1472.7
TEXAS	117.3	1091.6	1208.9
UTAH	13.1	103.2	116.3
VERMONT	0.4	10.4	10.8
VIRGINIA	225.2	225.8	451.0
WASHINGTON	38.1	371.0	409.1

Question 17:

Please provide SO_2 emission levels for each State in 1980.

Response:

The attached table which was recently prepared in response to another Congressional request, contains the requested information.

SO2 Emission Estimates by Source Sector, 1970 to 1984 (1000 short tons)

	1970			1975			1980			1984			Percent Change in Total Emissions, 1970 to 1984
	Util	Non-Util	Total	Util	Non-Util	Total	Util	Non-Util	Total	Util	Non-Util	Total	
Alabama	758.1	180.1	938.2	884.9	231.8	1,116.7	560.2	227.8	788.0	490.7	237.4	728.1	(22.4)
Arizona	4.0	2,261.7	2,265.7	48.1	1,391.1	1,439.2	84.7	708.4	793.1	90.8	447.7	538.5	(76.2)
Arkansas	9.2	25.3	34.5	16.0	50.4	66.4	38.3	49.8	88.1	73.0	49.2	122.2	254.1
California	40.6	519.4	560.0	114.0	384.4	498.4	85.0	489.2	574.2	14.7	369.9	384.6	(31.3)
Colorado	37.1	50.2	87.3	56.1	54.5	110.6	93.3	57.1	150.4	78.8	63.0	141.7	62.4
Connecticut	193.0	94.7	287.7	32.0	35.5	67.5	29.4	33.0	62.4	54.5	26.5	81.0	(71.9)
Delaware	44.3	34.9	79.2	34.1	22.2	56.3	54.5	46.9	101.4	72.1	61.6	133.7	68.8
District of Columbia	74.5	52.8	127.3	9.8	15.0	24.8	1.9	4.2	6.1	1.4	9.1	10.5	(91.8)
Florida	420.0	266.5	686.5	574.4	248.7	823.1	650.4	346.6	997.0	600.3	386.8	987.0	43.8
Georgia	293.6	124.0	417.6	564.1	100.4	664.5	705.8	112.1	817.9	824.8	109.1	933.9	123.6
Idaho	0.0	35.4	35.4	0.0	30.7	30.7	0.1	27.9	28.0	0.0	43.4	43.4	22.6
Illinois	1,871.9	787.2	2,659.1	1,779.2	459.0	2,238.2	1,191.0	388.2	1,579.2	1,079.6	301.4	1,381.0	(48.1)
Indiana	1,533.8	498.8	2,032.6	1,600.2	463.3	2,063.5	1,644.3	432.1	2,076.4	1,347.8	316.8	1,664.6	(18.1)
Iowa	228.6	154.9	383.5	213.5	100.4	313.9	231.6	106.6	338.2	166.0	142.8	308.9	(19.5)
Kansas	80.3	51.2	131.5	137.4	48.7	186.1	221.8	58.9	280.7	136.7	74.1	210.8	60.3
Kentucky	1,138.4	219.1	1,357.5	1,276.8	104.4	1,381.2	1,052.3	132.0	1,184.3	638.2	138.5	776.7	(42.8)
Louisiana	0.1	179.1	179.2	12.7	216.3	229.0	39.9	375.4	415.3	49.4	351.7	401.1	123.8
Maine	33.3	57.1	90.4	20.4	57.0	77.4	14.3	51.7	66.0	12.2	73.3	85.5	(5.5)
Maryland	327.1	150.3	477.4	205.6	104.7	310.3	245.6	113.4	359.0	211.1	54.3	265.4	(44.4)
Massachusetts	319.1	254.1	573.2	103.7	171.9	275.6	269.1	77.0	346.1	230.0	63.2	293.2	(48.9)
Michigan	1,197.1	598.3	1,795.4	1,070.6	349.5	1,420.1	603.7	301.4	905.1	592.9	286.3	879.2	(51.0)
Minnesota	271.5	135.4	406.9	201.7	99.2	300.9	122.6	64.5	187.1	104.6	77.6	182.1	(55.2)
Mississippi	41.4	87.2	128.6	114.8	96.3	211.1	137.7	126.1	263.8	83.0	134.7	217.7	69.3
Missouri	631.2	358.1	989.3	1,072.1	222.6	1,294.7	1,100.0	183.4	1,283.4	1,039.5	143.2	1,182.8	19.6
Montana	9.1	410.2	419.3	15.0	166.6	181.6	30.8	131.9	162.7	10.8	101.2	112.0	(73.3)
Nebraska	36.0	48.3	84.3	28.2	28.0	56.2	49.8	22.6	72.4	41.4	24.7	66.1	(21.6)
Nevada	7.5	299.7	307.2	34.0	225.6	259.6	45.3	174.9	220.2	53.3	64.8	118.1	(61.6)
New Hampshire	67.5	29.6	97.1	63.0	18.6	81.6	72.9	13.7	86.6	65.6	16.1	81.7	(15.9)
New Jersey	295.1	326.5	621.6	118.0	229.3	347.3	107.3	221.9	329.2	105.7	172.0	277.7	(55.3)
New Mexico	91.8	431.2	523.0	85.3	398.2	483.5	112.5	171.2	283.7	110.6	126.1	236.6	(54.8)
New York	657.7	791.3	1,449.0	583.2	496.7	1,079.9	466.4	467.1	933.5	483.3	289.8	773.1	(46.6)
North Carolina	419.3	163.1	582.4	437.6	127.5	565.1	430.1	153.1	583.2	374.2	164.5	538.7	(7.5)
North Dakota	32.8	27.4	60.2	46.9	26.0	72.9	93.3	28.0	121.3	114.8	26.9	141.6	135.3
Ohio	2,243.3	1,011.2	3,254.5	2,661.9	571.8	3,233.7	2,346.2	467.5	2,813.7	2,043.7	539.0	2,582.7	(20.6)
Oklahoma	0.2	86.3	86.5	2.6	72.1	74.7	59.4	87.9	147.3	86.5	49.4	135.9	57.2
Oregon	0.5	60.7	61.2	1.2	47.3	48.5	12.2	48.6	60.8	0.0	42.8	42.8	(30.1)
Pennsylvania	1,531.5	921.2	2,452.7	1,440.3	621.3	2,061.6	1,415.7	595.2	2,010.9	1,365.1	239.4	1,604.5	(34.6)
Rhode Island	23.4	38.3	61.7	5.2	19.5	24.7	4.2	9.2	13.4	3.2	6.5	9.7	(84.3)
South Carolina	120.8	90.3	211.1	143.5	65.2	208.7	202.8	100.8	303.6	149.0	111.0	260.0	23.2
South Dakota	53.8	10.0	63.8	32.6	8.4	41.0	38.2	9.2	47.4	25.4	13.1	38.5	(39.7)
Tennessee	865.0	190.1	1,055.1	1,350.9	125.5	1,476.4	1,003.0	173.6	1,176.6	742.8	179.1	922.0	(12.6)
Texas	1.4	858.7	860.1	85.1	949.6	1,034.7	297.6	1,014.4	1,312.0	433.1	803.8	1,236.9	43.8
Utah	10.2	273.5	283.7	19.6	95.6	115.2	27.7	85.9	113.6	29.9	77.0	106.9	(62.3)
Vermont	3.6	9.7	13.3	0.4	6.0	6.4	0.0	6.7	6.7	0.3	7.7	8.0	(39.9)
Virginia	279.1	220.9	500.0	222.7	151.3	374.0	159.4	153.8	313.2	122.9	182.2	305.1	(39.0)
Washington	0.0	174.9	174.9	37.0	154.8	191.8	82.5	197.0	279.5	71.1	168.1	239.2	36.8
West Virginia	746.7	250.9	997.6	1,300.4	176.4	1,476.8	1,059.7	145.1	1,204.8	870.9	149.0	1,019.9	2.2
Wisconsin	608.8	308.4	917.2	555.9	138.5	694.4	523.3	143.4	666.7	377.2	195.1	572.3	(37.6)
Wyoming	38.5	46.4	84.9	76.4	52.5	128.9	167.7	75.0	242.7	106.6	110.2	216.7	155.3
U.S. Total	17,691.9	14,254.4	31,946.3	19,489.1	10,030.9	29,520.0	17,985.6	9,211.2	27,196.8	15,779.1	7,820.9	23,600.0	(26.1)

Prepared by: E.H. Pechan & Associates, Inc., Springfield, VA.

Sources: Gschwandtner 1985, U.S. Environmental Protection Agency 1986.

Question 18:

The Acid Deposition Control Act, S. 2200, introduced by Senator Mitchell, requires each State in a 31-State "acid deposition impact region" to reduce SO_2 emissions below 1980 levels within 10 years.

a. If the bill were enacted January 1, 1987, please indicate how much each State would have to reduce by January 1, 1997, using 1980 baseline figures as required by the bill.

b. If the bill were enacted January 1, 1987, and if the States were required to achieve the same level of emissions per state as they would be required to achieve under the bill, please indicate how much each State would have to reduce using 1976 as a baseline instead of 1980.

c. Given the present (6/1/86) level of emissions, please indicate how much each State would still have to reduce to achieve the State's level of emissions required for January 1, 1997, under S. 2200.

d. If the bill were enacted January 1, 1987, as of January 1, 1997, please indicate how much each State would have reduced since 1976.

Response:

Attached is a letter and 2 tables prepared for us by E.H. Pechan and Associates, Inc. in response to questions 18(a)-(d).

E. H. PECHAN & ASSOCIATES, INC.
5537 Hempstead Way
Springfield, Virginia 22151

(703) 642-1120

July 2, 1986

Mr. David Bassett
AR-445
U.S. Environmental Protection Agency
Office of Program Development
Washington, D.C. 20460

SUBJECT: Utility SO_2 Emissions

Dear Dave:

The enclosed tables provide information which responds to some of the questions from Senator Ford.

As we discussed yesterday, all of these analyses are based on a "no growth" assumption which excludes effects of new plants and/or changes in utilization of existing plants. Such effects can be analyzed but their analysis is quite complex and these effects are, in any event, subject to considerable uncertainty. We can extend the analysis to include growth effects if time and resources are available.

Table 1 responds to questions 18(a), (b), and (c). It presents emission reduction targets computed using an "excess emissions" allocation formula using a 1.2 pound of SO_2 per million Btu plant cap rate and a total reduction requirement of 10 million tons across the 31-state region. The first column lists the required reduction by state calculated based on a 1980 base year. The second column is calculated using 1976 for the base year while the third column is calculated using 1985 as a base year. Data for 1985 has been provided in response to question 18(c) since emissions for 1986 have not yet been estimated.

Table 2 responds to question 18(d). This table reports the emissions in 1976, the allowed emissions using 1980 as the base year and the difference, i.e., the net reduction which would be required to achieve the target from 1976. Negative numbers in the third column indicate states whose allowable emissions under the formula would be greater than actual emissions in 1976. Remember, however, that growth was not factored into these calculations.

Please contact me if you have any questions on these tables or need any additional information.

Sincerely,

Ed

Edward H. Pechan

Enclosures

Table 1

Emissions Reductions Required to Meet S. 2200 Provisions Using Alternative Base Years and No Growth Assumptions

	SO2 Reductions in 1000's of short tons		
	Base Emissions Year of		
State	1980	1976	1985
Alabama	304.4	391.8	338.1
Arkansas	0.5	7.6	0.0
Connecticut	0.0	0.2	0.0
Delaware	16.7	21.4	17.8
District of Columbia	0.0	0.0	0.0
Florida	329.3	252.5	242.2
Georgia	469.0	240.6	711.9
Illinois	758.1	892.5	903.6
Indiana	1,190.6	924.8	1,253.7
Iowa	125.9	100.6	107.0
Kentucky	736.7	1,015.4	568.1
Louisiana	0.0	0.0	0.0
Maine	2.3	4.6	0.4
Maryland	107.6	72.7	110.3
Massachusetts	99.7	14.9	90.4
Michigan	239.0	469.6	58.6
Minnesota	56.9	88.4	23.2
Mississippi	72.3	61.5	73.7
Missouri	913.6	811.2	825.9
New Hampshire	49.0	22.8	52.2
New Jersey	38.2	28.6	34.8
New York	220.8	207.2	217.0
North Carolina	94.3	98.2	57.0
Ohio	1,598.2	1,823.3	1,944.1
Pennsylvania	877.7	756.9	849.2
Rhode Island	0.0	0.0	0.0
South Carolina	96.7	56.3	68.8
Tennessee	678.9	792.0	630.0
Vermont	0.0	0.2	0.5
Virginia	26.3	38.2	19.5
West Virginia	585.6	535.6	645.8
Wisconsin	311.9	270.6	156.0
31-State Region	10,000.0	10,000.0	10,000.0

Table 2

Emissions Changes from 1976 Required by S. 2200 Assumptions Using No Growth Assumptions

(SO2 Emissions in 1000's of short tons)

State	1976 Base	Allowed Emissions	Difference
Alabama	721.8	266.8	455.0
Arkansas	37.8	25.6	12.2
Connecticut	24.9	31.2	(6.3)
Delaware	61.7	35.8	25.9
District of Columbia	7.0	4.2	2.8
Florida	674.9	392.6	282.3
Georgia	512.9	290.4	222.5
Illinois	1,494.6	387.6	1,107.0
Indiana	1,481.1	389.1	1,092.0
Iowa	215.2	105.3	109.9
Kentucky	1,552.8	311.5	1,241.3
Louisiana	32.5	21.1	11.4
Maine	12.8	13.5	(0.7)
Maryland	220.7	116.3	104.4
Massachusetts	157.5	171.2	(13.7)
Michigan	902.6	331.0	571.6
Minnesota	223.4	115.7	107.7
Mississippi	154.1	58.3	95.8
Missouri	1,239.6	261.2	978.4
New Hampshire	51.1	32.2	18.9
New Jersey	114.9	65.1	49.8
New York	513.7	269.1	244.6
North Carolina	421.9	351.2	70.7
Ohio	2,856.0	610.3	2,245.7
Pennsylvania	1,459.9	630.5	829.4
Rhode Island	3.0	5.1	(2.1)
South Carolina	165.1	119.6	45.5
Tennessee	1,261.8	280.0	981.8
Vermont	0.4	0.3	0.1
Virginia	225.2	136.4	88.8
West Virginia	1,033.0	382.4	650.6
Wisconsin	469.7	149.6	320.1
31-State Region	18,303.6	6,360.4	11,943.2

Question 19:

Tremendous uncertainty has characterized the whole debate on acid rain. Taking into consideration the latest research, are the problems associated with acid rain growing at an increasing pace? Do you anticipate that the problems of forest decline and lake acidification will remain primarily a northern concern?

Response:

Although it is true that there is tremendous uncertainty regarding the acid rain problem, some aspects have greater uncertainty than others. We know, for example, that acid rain can contribute to lake acidification, but we have no basis to attribute forest decline to acid rain.

Our current understanding of the mechanisms of lake acidification suggests that most lakes in the Northeast may be in equilibrium with the level of acid deposition and respond directly to it. If this is true, without significant increases in deposition, we would not expect additional acidification to occur. In fact, there has been a significant reduction in SO_2 emissions over the past decade, which further reinforces our expectation that significant new damage in the Northeast is unlikely at current levels of emissions and deposition. Data from a limited number of benchmark streams monitored in the Northeast by the USGS have documented decreases in sulfate concentrations and increases in alkalinity over the period of the emissions decreases.

In the Southeast, however, we believe that different soil conditions most likely will result in delayed response of most lakes and streams to levels of deposition. This would mean that the effects of past and present acid deposition on Southeastern lakes are not yet apparent, and decades may pass before significant changes are observed in acidity and alkalinity.

Question 20:

Scientists have indicated that a number of pollutants are involved in the forest decline usually attributed to acid rain. Ozone, excess nitrogen, and organic chemicals are among the alleged culprits. Do you remain convinced that sulfur and nitrogen oxides are the principal agents in lake and forest degradation? What is being done to affect the larger menu of possible contaminants?

Response:

As stated, in response to question 19, the great differences in our present understanding of aquatic and forest effects attributable to acid rain require that they be discussed separately.

There are presently a wide variety of competing hypotheses to explain forest decline. Many of these involve air pollution, particularly ozone, and some implicate acid deposition and/or its precursor pollutants SO_2 and NO_x. There is as yet no scientific basis on which to choose among these different hypotheses.

On the other hand, there is support for the contention that sulfur deposition has contributed to lake acidification in the Northeast. In addition, growing scientific and policy attention is being given to nitrogen deposition, which may contribute to episodic acidification through the phenomenon of "spring shock."

Ambient concentrations of sulfur dioxide, nitrogen oxides, ozone, and volatile organic compounds are all controlled under the current Clean Air Act. A central question of the current debate is whether these controls are adequate to address the known and potential effects of acid rain. We do not believe that our current scientific knowledge is sufficient to answer that question.

Question 21:

The clean-coal program will lead to staged development -- industry will build on what is essentially a large demonstration program. While this may be a "least cost" scenario, it will take time. In your opinion, what will be the environmental cost of a delay?

Response:

The environmental cost of not initiating additional emission controls now can only be determined if we know the current damage and can estimate the environmental benefits from taking a specific action. Our aquatic, forest, and materials effects efforts are focused on precisely these questions: What is the extent of current damage? What are the mechanisms that cause this damage, so that we can understand and predict the benefits of reducing pollutant loadings? What is the relationship between emissions of various pollutants and pollutant loadings?

From the information we have we do not see an impending environmental crisis--a situation which would raise the potential costs of delay. We believe, therefore, that the prudent course is to obtain the significant scientific results we expect over the next 2 to 3 years and to base our decision making on those results.

QUESTIONS SUBMITTED TO

DAVE BERGER

HEARING ON
CLEAN COAL TECHNOLOGY AND ACID RAIN CONTROL

1. EPA Administrator Thomas, on behalf of the Administration, stated that,

> "we do not yet believe that the current state of knowledge can sustain any judgement with respect to the level of emission reductions needed to prevent or eliminate damage."

Do you agree with this statement?

A: I agree that SO_2 and NO_x are sources of environmental damage and that their emission levels should be reduced. However, I am uncertain as to the level of emission reductions needed to prevent or eliminate damage.

2. EPA Administrator Thomas added:

> "this is true even for the area of greatest scientific understanding, sulfur emission and surface water acidification. In the area of the impact of acid deposition on forests, we have yet to determine if a cause and effect relationship exists."

Do you agree with this assessment of current knowledge?

A: In general, yes. It is, however, generally acknowledged that acid depositions introduce varying degrees of stress upon terrestrial and aquatic systems. A direct, cause and effect relationship has yet to be substantiated.

3. On the basis of current knowledge of the causes of acid rain, in your judgement, can we formulate a control strategy that will assure achievement of the intended mitigation of acid rain once the prescribed control investments have been made? In other words, can we determine what pollutants need to be controlled, the size reductions that are called for, where the reductions should take place, and over what time frame they should be implemented?

A: What is meant by "assure achievement of the intended mitigation of acid rain"? Without knowing the intended objective, this question cannot be answered.

4. There has been considerable discussion of the need to place emphasis on the development of clean coal technologies with retrofit application. For example, the Special Envoys Report emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

EPA Administrator Thomas emphasized in his testimony that "the most important application category for the focus of clean coal technology development would be the coal-fired retrofit application". Do you agree?

a. In your judgement, does the DOE Clean Coal Technology program adequately reflect this need? Or does the program place too much priority on technologies applicable to new construction?

b. Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control? Should they be?

A: I concur in Administrator Thomas' assessment.

a. The current U.S. DOE Clean Coal Technology program does not feature greater/lesser priorities. It does, however, contain an inadvertant disincentive to retrofit technologies applied to existing power generation facility hosts.

b. Yes. Although a strict definition, as offered in my testimony, would include only those technologies capable of achieving net SO_2/NO_x reductions in the short term.

5. Under what circumstances will life-extension result in reduced atmospheric emissions?

A: To the extent that plant efficiency or control technologies are installed as part of life extension work, reduced atmospheric emissions will follow.

6. What is the potential that the types of clean coal technologies under discussion will be able to meet New Source Performance Standards without the use of scrubbers?

A: Not all potential technologies will be singly capable of attaining NSPS limits. This is especially true for retrofit technologies, where combinations of individual technologies may be required to meet NSPS.

7. Are the technologies being developed by the DOE clean coal technology program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?

A: This question cannot be answered in advance of U.S. DOE's selection of projects. It is generally acknowledged, however, that emission reduction regulatory requirements could hasten the development and deployment of retrofit technologies.

8. Mr. Donald Bauer, on behalf of DOE, stated that performance testing of clean coal technologies under consideration by DOE generally will not be completed until the early to mid-1990s. He concluded with the observation that "if the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options". Do you agree?

A: I agree with Mr. Bauer's assessment of time required to adequately demonstrate clean coal technologies. As applied to Ohio, H.R. 4567 would diminish prospects for emerging clean coal technologies by reason of both the timetable and aggregate size of reduction required of the state in Phase I.

9. One of the premises behind the Clean Air Act was that industry would gradually retire old facilities and replace them with new installations subject to "new source performance standards". Consequently, there would be a gradual improvement in air quality. In your judgements has this occurred?

In asking this question it is observed that EPA Administrator Thomas, commenting on plant life extension trends, stated that, "this postpones the rate at which new sources will replace existing sources, making New Source Performance Standards a less effective way of reducing overall emissions in the near or middle term".

A: Neither plant retirement nor new plant construction has proceeded at the pace presumed in the Clean Air Act.

10. In your opinion. what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the various legislative proposals before the Congress? For example, is the electric utility industry likely to rely on extension of the life of existing facilities rather than their retirement and replacement with new facilities?

A: First, the various legislative proposals before Congress involving new acid rain regulatory requirements differ widely in emission standards and how these would apply. Generally, stricter emission limits will force retirement of existing facilities in favor of new facilities.

11. In your judgement, to what extent is industry's decision to extend the life of an existing facility influenced by regulatory policies? For example, as I understand EPA regulations, at a certain point the costs of retrofitting an existing facility become great enough that it runs the risk of being classified as a new one subject to New Source Performance Standards. Would you comment.

A: Regulatory policies are always important factors in utility investment decisions. Increasingly stringent emission limits applied to existing facilities would, in many cases, result in costs sufficient to trigger NSPS requirements.

12. The Clean Air Act provides for an extension of compliance dates for facilities that propose to utilize new or innovative technologies to comply with emissions standards. In your judgement, has this authority been effectively implemented by the EPA?

A: I have no direct experience upon which to base a conclusion.

13. What is the national average cost of FGD retrofit per kilowatt? And, what would be the cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements? What would be the differential cost between implementation of the above options?

A: Average costs for FGD retrofit installations are very misleading. As emphasized in my testimony, costs for individual facilities are extremely sensitive to site characteristics and original plant design. Ohio's Environmental Protection Agency projects capital cost/kw for FGD retrofits on Ohio facilities from a low of $169/kw for one plant to a high of $582/kw for another. Also significant is the comparatively large annual operating and maintenance costs associated with FGD systems that fall within a range of 6 to 8 mills/kwh.

14. What, in your judgement, are the estimated costs of implementing proposed acid rain legislation? Would you indicate the sources of such cost estimates and whether you agree, or disagree, with such analysis?

A: The impact analysis of H.R. 4567 prepared by the Ohio Coal Development Office projects the following cost of compliance for Ohio:

Compliance Approach	Total Capital Cost (Million $)	Total Annual Cost (Million $)
Fuel Switching	773.3	606.4
FGD Retrofits	4227.2	1219.2
Combined Fuel Switching & FGD Retrofit	2970.3	991.0

Implementation of H.R. 4567 in its present form would also cost 11,000 Ohioans their jobs.

15. What in your judgement, are the comparative roles of different source contributors of air pollution as contributing factors in acid precipitation? Would you indicate the sources of such information and whether you agree, or disagree, with such analysis?

A: Sulfur dioxide and nitrogen oxides appear to be the largest contributors of precursors.

16. In your view, is it realistic to expect emerging clean coal technologies to significantly contribute to SO_2 and NO_x reductions prior to the year 2000?

A: Yes. As stated in my testimony, from five to ten years of accelerated development and demonstration effort is still required, making clean coal technologies commercially available by 1995.

17. From your state's perspective, would you prefer to operate a clean coal technology program, or continue to operate under a federal program?

A: I'm not certain in my understanding of the choice posed by this question. Ohio is already participating on a joint basis with the federal programs and anticipates expanding upon this foundation through projects concurrently supported by US. DOE and the Ohio Coal Development Office via the Clean Coal Technology program.

18. Each of your states have a strong interest in seeing coal developed to a greater degree. Does this interest mitigate against state efforts toward SO_2 and NO_x reduction?

A: No.

19. Having an interest in DOE's solicitation on clean coal technologies, do you believe the range of projects currently reflects the best set of options for future clean coal applications?

A: No, because retrofit proposals are underrepresented.

20. Do you believe DOE's "payback" component of the solicitation has in any way dampened interest in proposing new technologies?

A: Yes.

21. How would you characterize your state's relationship with the federal government on acid rain and/or clean coal technologies?

A: For acid rain, it is difficult to characterize a relationship due to the complexity of participants and issues involved. Ohio seeks to be a co-sponsor of worthy clean coal technology projects also selected by U.S. DOE.

22. In your statement you mention four criteria set forth by Governor Celeste in previous testimony; job protection, fairness and affordability, coverage of compliance costs and effectiveness in reducing acid rain. Obviously the Ohio program is designed to meet these tests. In your view how does the federal program stand up to these criteria?

A: Job Protection

Under H.R. 4567, compliance options are at each state's discretion. A fuel switching compliance strategy could result in the loss of over 11,000 jobs in Ohio's coal mining regions. Even if control technolgoies were applied to achieve more than one-half of emission reductions mandated in Ohio, the total job loss in Ohio could exceed 7,000 jobs and coal production would be cut by 34% from current depressed levels.

Fairness and Affordability

Emission reductions required of Ohio far exceed the state's proportion of national SO_2 emission levels. H.R. 4567 would require Ohio to shoulder 15.9% of the total national SO_2 emission reduction even though its proportion of total national SO_2 emissions in 1980 was 9.9%.

Further, the annual cost of H.R. 4567 to Ohio could exceed half a billion dollars at minimum, applying conservative assumptions regarding low sulfur coal premiums in a total fuel switch compliance approach. The capital costs for technology controls could exceed $4.0 billion. Ohioans have already financed nearly $2 billion in pollution controls to meet current Clean Air Act requirements.

A mixed control strategy involving technology controls and fuel switching could boost electric rates by at least 5.8% for Toledo Edison and by 19.3% for Ohio Power. Only residential customers of Ohio Edison and Toledo Edison could expect rate increases of less than 10%. Equally important, since Ohio industry pays for nearly 50% of all electricity used today in Ohio, increased electric rates would worsen Ohio's competitive position.

Coverage of All Costs

The proposed acid rain control fund barely reduces H.R. 4567's costs to Ohio. Only a portion of the annual cost requirement would be eligible for national funding. Capital cost to Ohio could range from $770 million to $4.2 billion under various compliance strategies. Annual operating and maintenance costs could exceed $565 million per annum.

Effectiveness in Solving the Acid Rain Problem

H.R. 4567 makes no attempt to relate emission reductions to the most acid sensitive regions. Instead, it seeks to implement uniform emission rates nationwide. By assigning the largest reductions to the Midwest, the legislation fails to maximize reductions in the most acid sensitive areas.

23. To what extent do you believe the Ohio program will allow increased development of coal reserves?

A: To the extent the clean coal technologies result in an expansion of markets for higher sulfur coal, increased development of Ohio coal reserves will follow.

24. You mention rapid cost recovery (through the State PUC process) in addition to financial grant support. To what extent has the clean coal program added to electric rates in Ohio?

A: The rapid cost recovery provision is just now being implemented. Accordingly, no projects have been approved via this procedure and no increase in electrical rates has ensued.

25. You state in your prepared remarks that, quote "in the context of prospective acid rain controls and the Joint Envoys Report, only retrofit options that achieve net sulfur and nitrogen emission reductions are worthy of serious consideration." If this is the thrust of federal policy does it make sense to pursue short-term clean coal technologies?

A: My point is that retrofit options are not the current thrust of federal policy as reflected in the U.S. DOE Program Opportunity Notice (PON) for Clean Coal Technologies. Instead, it is one of several technology facets encouraged.

26. Your statement is succinct in discussing various technological options. In your view, which clean coal technologies are most promising for the 1990's?

A: See attached Table 4.

TABLE 4 CLEAN COAL TECHNOLOGY OVERVIEW

Type of Clean Coal Technology	Percent Sulfur Removal	Development Status(1)	Can Be Applied At Existing Facilities	Cost Effectiveness(2)	Comment
Pre-Combustion					
Advanced Physical Cleaning	30-60%	Pilot Plant	Yes	High	Overall sulfur reduction limited to pyritic fraction. Other benefits in coal consistency, ash reduction and Btu enhancement. Pre-1990 commercial availability
Chemical Cleaning	10-100%	Bench Scale	Yes	Medium-Low	Potential for extremely high sulfur and ash reduction. Very expensive, yielding fuel too costly for boiler use. Post-1990 commercial availability
Microbiological Cleaning	10-60%	Bench Scale	Uncertain	Unknown	In early developmental stage. Post 1990 commercial availability
During Combustion					
Advanced Combustors	40-60%	Demonstration (industrial)	Yes	Medium	Simultaneous SO_2, NO_x and ash reduction. Sulfur reduction potential limited. Aimed at oil/gas retrofits. Pre-1990 commercial availability
Lime Injection (LIMB)	40-60%	Demonstration	Yes	Medium-High	Simultaneous SO_2 and NOx reduction. Requires capacity for additional ash collection. Post-1990 commercial availability
Gasification	95%+	Demonstration	Yes	Low	Requires product gas treatment for tar and sulfur removal. Combined cycle turbine efficiency gains possible. Pre-1990 commercial availability
Fluidized Bed	90%+	Demonstration	Yes	Medium-High	Simultaneous SO_2 and NO_x reduction. High degree of fuel flexibility. Requires scale-up. Pressurized offers combined cycle potential. Pre-1990 commercial availability
Alternate Fuels (Briquetts)	40-60%	Demonstration	Yes	Medium	Limited to stoker fed units. Requires low cost coal fines/culm feedstock. Pre-1990 commercial availability
Post-Combustion					
Advanced "Wet Scrubbing"	80-90%	Demonstration	Some	Low	Enhanced sorbent and operating demonstrations underway. Retrofit cost quite site specific and variable. Pre-1990 commercial availability
Advanced "Dry Scrubbing"	80-90%	Demonstration	Some	Medium-Low	Demonstrations underway on more efficient sorbents and regenerable systems. Retrofit cost quite site specific and variable. Pre-1990 commercial availability
Dry Sorbent Injection	10-60%	Pilot Plant	Yes	Medium-High	Tests underway on 1 to 5 Mw installations. Requires capacity for additional ash collection. Pre-1990 commercial availability

Sources: "Technologies for Controlling Pollutants from Coal Combustion, Wade Ponder U.S. EPA Research Triangle Park, October, 1985

"Supplemental Report to Congress on Emerging Clean Coal Technologies", U.S. DOE, August, 1985

(1) and (2) See reverse side

QUESTIONS FOR ICGI AND THE OHIO COAL DEVELOPMENT OFFICE

1. What options are available to State governors to achieve the emissions levels required in the legislation?

A: My response is framed in the context of H.R. 4567, as amended. Three options or combinations thereof could be utilized: fuel switching; FGD retrofit; and, innovative clean coal technologies. The appeal of innovative clean coal technologies, however, is significantly diminished in Ohio by the size of reduction imposed on Ohio by 1993. Moreover, the legislation also precludes election of early plant retirement, load management and energy conservation options due to its reliance upon a #SO_2/MmBtu standard.

2. Please describe whether, in your belief, the legislation provides an incentive for governors to select a particular methodology to achieve required emission levels.

A: I would prefer to emphasize the bias implicit in the fuel switching alternative authorized by H.R. 4567, as amended. At current cost premiums for low-sulfur compliance coal, the fuel switching option is half as costly to Ohio, in total annual cost, than a FGD retrofit option.

3. Please discuss the impact of the legislation on the development and commercialization of clean coal technologies.

A: H.R. 4567, as amended, and applied to Ohio results in disincentives to the development and commercialization of clean coal technologies. Their application, in the scheme of emission reductions imposed on Ohio, can only be considered for the Phase II requirements. Moreover, if the capital cost intensive FGD retrofit option was elected for Phase I requirement, utilities would more likely opt for fuel switching to meet the Phase II requirements. In addition, the requirement for contingency measures, should innovative clean coal technologies fail to meet emission limits, also mitigates against their development and application.

4. Please identify the relative costs to utilities of achieving the required emission levels through the use of continuous emission controls, fuel switching from high sulfur to low sulfur or non-coal sources, or conserving energy to reduce the need to generate electricity from high sulfur coal burning plants.

A: Estimated annual compliance cost to Ohio utilities from H.R. 4567, as amended, is presented within a framework of three options. Not included is energy conservation as no emission credit is authorized by the legislation for this option. All cost estimates are pre-subsidy 1985 dollars for Ohio-located facilities only.

H.R. 4567, as Amended, Annual Cost to Ohio Utilities ($ Millions)

OPTIONS

Company	FGD Retrofit	Fuel Switching	Mixed
Cincinnati Gas & Electric	226.9	136.4	201.1
Cleveland Electric Illuminating	156.1	181.9	203.0
Columbus & Southern Ohio Electric	189.5	106.8	132.5
Dayton Power & Light	140.4	82.4	140.4
Ohio Edison	168.9	163.0	148.9
Ohio Power	395.6	281.4	355.5
Toledo Edison	28.9	31.0	48.3
Ohio Valley Electric Cooperative	109.5	90.7	62.9
Buckeye Power	84.6	44.8	84.6
	$1,500.5	$1,118.3	$1,377.2

Public Service Commission Of West Virginia

201 Brooks Street, P. O. Box 812
Charleston, West Virginia 25323

July 2, 1986

Richard Grundy, Director
Oversight and Investigation
United States Senate Committee on Energy
and Natural Resources
SH-312
Washington, D. C. 20510

Dear Mr. Grundy:

This is in response to Chairman McClure's letter dated June 13, 1986, requesting responses to a list of questions submitted by various members of the Committee. Attached herewith you will find my responses to those questions. The responses do not repeat each question so I am also attaching copies of the original list of questions.

I appreciate this opportunity to respond to additional questions as well as the original opportunity to appear and make a statement at the Committee's Oversight Hearings on Clean Coal Technology Development and Strategies for Acid Rain Control. If you, or any Committee Members, have any additional questions or would like expanded responses to any of their questions, please feel free to contact me.

Very truly yours,

Michael D. Greer

Michael D. Greer,
Chairman

MDG:cr

Question 1:

I do agree with EPA Administrator Thomas with regard to emission reductions and acid deposition. Although I appeared before the Committee in my capacity as a utility regulator, and not an environmental expert, I have attempted to review the information available with regard to utility emissions and their contribution to acid rain. As I indicated in my prepared statement I would not accept the limited knowledge that is presently available as sufficient justification for the mass expenditures of utility dollars. For the same reasons, it appears to me to statutorily mandate massive expenditures is a highly imprudent decision.

Question 2:

I agree, as indicated in the answer to question 1.

Question 3:

My response to this question is the same as my response to the first two questions. If I were sitting in judgement as a regulator I could not find that a compelling case had been made for the SO2 and NOX emission reductions mandated by many of the emission control bills presently before Congress.

Question 4:

I do not agree that the focus for clean coal technology development should be limited to coal-fired retrofit application. I believe that clean coal technology development is an important development both for retrofit and new technology applications.

4a. As I understand the DOE Clean Coal Technology program I see applicability both to new construction and retrofit application

4b. It would appear that the clean coal technologies potentially funded by DOE will be appropriate for reducing SO2 and NOX emissions. Whether such reductions will provide a satisfactory response to the acid deposition problem is currently unclear. To the extent that coal-fired blowers are contributing to acid deposition because of high levels of SO2 and NOX emissions, I believe that the clean coal technologies will reduce that contribution.

Question 5:

Life extensions brought about by scrubber retrofitting, coal washing, dry scrubbing and fluidized bed technologies will result in reduced emissions.

Question 6:

I believe there is a very high probability that some of the fluidized bed applications would be able to meet New Source Performance Standards without the use of scrubbers.

Question 7:

I believe that technology which is being developed, once proven to be feasible and economically desirable, will likely be utilized under present regulatory requirements.

Question 8:

I absolutely agree. HR 4567 will require immediate decisions which will have to be based upon available conventional technology.

Question 9:

I believe that a gradual improvement in air quality has occurred. All data which I have reviewed indicates substantial gains over the last ten years.

Question 10:

It is difficult to answer this question without looking at the "various legislative proposals before the Congress". Looking at one proposal which is moving rapidly through the House of Representatives, HR 4567, I do not believe that there is any doubt that retirement and replacement with new facilities is a highly likely response by the electric utility industry. Because of the Clean Air Act and New Source Performance Standards this will result in substantial reductions in SO2 and NOX emissions; however, there will be a tremendous cost to the utility customers of such a response.

Question 11:

I have not observed that the electric utility industry is influenced by EPA regulations to a great degree with regard to its decisions to extend the life of an existing facility. I believe that the projections of demand growth, ratemaking policies and financial conditions heavily influence electric industry decisions to build new capacity.

Question 12:

At this time I do not have sufficient information to respond to this question.

Question 13:

The Staff of the Public Service Commission of West Virginia has based FGD retrofit estimates on an average cost of $250 per Kilowatt. We have estimated that the capital costs and operating costs associated with a 100% scrubber technology would equate to approximately 1.2¢ per Kwh. We believe that alternate approaches, such as shifting to low sulfur coal, could be accomplished at much lower costs; approximately .4¢ per Kwh. As I explained in my statement before the Subcommittee, however, we do not believe that all facilities could be brought into compliance with the specific requirements of a bill such as HR 4567 through fuel shifting.

Question 14:

As presented in my prepared statements to the Subcommittee the Public Service Commission of West Virginia Staff has calculated the costs of implementing HR 4567 at approximately .8¢ per Kwh. For total generation in the State of West Virginia this would amount to over $600 million per year.

Question 15:

As indicated in several other responses, I have not been able to find any conclusive studies or evidence that ties acid deposition to the different source contributors. I am not qualified to attempt to analyze various studies and data to pass judgement on the comparative roles of different source contributors to the acid deposition problem.

Question 16:

No. Since the clean coal technology is largely still in a demonstration mode, it is unlikely that "significant' reductions in emission levels will occur before 2000.

Question 17:

I believe that the federal program would be preferable if it were administered in a more positive manner.

Question 18:

No. I believe that the coal producing states have as great, or a greater, interest in the technology for SO2 and NOX reduction than the other states. The economic future of West Virginia is tied to the health of our coal industry. Therefore, we have a great interest in developing effective, clean and efficient ways to utilize our coal resources.

Question 19:

Yes. I believe that the projects currently under consideration are a mix of the best options presently conceivable for future clean coal applications.

Question 20:

No. I believe that a partnership between government and private industry is an effective way to assure efficient, cost effective and commercially feasible demonstration projects. I do not believe that the private sector should be expected to fully finance the developmental technologies.

Question 21:

I believe that West Virginia's relationship with the federal government on acid rain and clean coal technologies is either strained or friendly, depending on which branch of federal government is involved. Generally, I believe that our interests are the same, and those are to develop domestic energy sources while maintaining and achieving high environmental standards.

Question 22:

New technology development requires capital, and I believe that the electric utility industry has a limited amount of capital to invest. Decisions will be made with regard to such capital investment based on statutory and regulatory requirements. If the industry is forced to adopt a "quick fix", there will be neither sufficient capital nor industry incentive to concurrently proceed with the clean coal technologies. Faced with emissions standards that must be met immediately the industry will utilize existing technology and invest its capital in long-term facilities, thereby providing long-term solutions to its emission problems. This will push new technology development thirty to forty years down the road and, because of limited capital sources, I believe that such new technology will be stifled and development will cease for a lengthy period.

Question 23:

I believe that a more moderate percentage reduction approach over a twenty to twenty-five year period would be a much more reasonable timetable.

Question 24:

Yes. Our best estimates are that some of these plants will be retrofitted with existing scrubber technology but some will have to be retired.

Question 25:

As a regulator, I believe that the most efficient and cost effective alternatives should be approved insofar as electric rates are concerned. I certainly believe that moderate investments in clean coal technology programs are preferable to massive retrofitting of existing scrubber technology and/or premature retirement of existing units. However, such clean coal technology investments would not be a prudent course of action if we are faced with accelerated schedules for compliance such as those contained in HR 4567.

Question 26:

Clean coal technology is a viable solution to SO2 and NOX emission "problems". To the extent that these emission reductions will contribute to a solution to the acid deposition problem, then the clean coal technology is a solution and advocated by the West Virginia Commission.

QUESTIONS SUBMITTED TO

MICHAEL D. GREER

HEARING ON
CLEAN COAL TECHNOLOGY AND ACID RAIN CONTROL

1. EPA Administrator Thomas, on behalf of the Administration, stated that,

   > "we do not yet believe that the current state of knowledge can sustain any judgement with respect to the level of emission reductions needed to prevent or eliminate damage."

   Do you agree with this statement?

2. EPA Administrator Thomas added,

   > "this is true even for the area of greatest scientific understanding, sulfur emission and surface water acidification. In the area of the impact of acid deposition on forests, we have yet to determine if a cause and effect relationship exists."

   Do you agree with this assessment of current knowledge?

3. On the basis of current knowledge of the causes of acid rain, in your judgement, can we formulate a control strategy that will assure achievement of the intended mitigation of acid rain once the prescribed control investments have been made? In other words, can we determine what pollutants need to be controlled, the size reductions that are called for, where the reductions should take place, and over what time frame they should be implemented?

4. There has been considerable discussion of the need to place emphasis on the development of clean coal technologies with retrofit application. For example, the Special Envoys Report emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

   EPA Administrator Thomas emphasized in his testimony that "the most important application category for the focus of clean coal technology development would be the coal-fired retrofit application". Do you agree?

   a. In your judgement, does the DOE Clean Coal Technology program adequately reflect this need? Or does the program place too much priority on technologies applicable to new construction?

   b. Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control? Should they be?

5. Under what circumstances will life-extension result in reduced atmospheric emissions?

6. What is the potential that the types of clean coal technologies under discussion will be able to meet New Source Performance Standards without the use of scrubbers?

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7. Are the technologies being developed by the DOE clean coal technology program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?

8. Mr. Donald Bauer, on behalf of DOE, stated that performance testing of clean coal technologies under consideration by DOE generally will not be completed until the early to mid-1990s. He concluded with the observation that "if the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options". Do you agree?

9. One of the premises behind the Clean Air Act was that industry would gradually retire old facilities and replace them with new installations subject to "new source performance standards". Consequently, there would be a gradual improvement in air quality. In your judgements has this occurred?

   In asking this question it is observed that EPA Administrator Thomas, commenting on plant life extension trends, stated that, "this postpones the rate at which new sources will replace existing sources, making New Source Performance Standards a less effective way of reducing overall emissions in the near or middle term".

10. In your opinions, what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the various legislative proposals before the Congress? For example, is the electric utility industry likely to rely on extension of the life of existing facilities rather than their retirement and replacement with new facilities?

11. In your judgement, to what extent is industry's decision to extend the life of an existing facility influenced by regulatory policies? For example, as I understand EPA regulations, at a certain point the costs of retrofitting an existing facility become great enough that it runs the risk of being classified as a new one subject to New Source Performance Standards. Would you comment.

12. The Clean Air Act provides for an extension of compliance dates for facilities that propose to utilize new or innovative technologies to comply with emissions standards. In your judgement, has this authority been effectively implemented by the EPA?

13. What is the national average cost of FGD retrofit per kilowatt? And, what would be the cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements? What would be the differential cost between implementation of the above options?

14. What, in your judgement, are the estimated costs of implementing proposed acid rain legislation? Would you indicate the sources of such cost estimates and whether you agree, or disagree, with such analysis?

15. What in your judgement, are the comparative roles of different source contributors of air pollution as contributing factors in acid precipatation? Would you indicate the sources of such information and whether you agree, or disagree, with such analysis?

16. In your view, is it realistic to expect emerging clean coal technologies to significantly contribute to SO2 and NOx reductions prior to the year 2000?

17. From your state's perspective, would you prefer to operate a clean coal technology program, or continue to operate under a federal program?

18. Each of your states have a strong interest in seeing coal developed to a greater degree. Does this interest mitigate against state efforts toward SO2 and NOx reduction?

19. Having an interest in DOE's solicitation on clean coal technologies, do you believe the range of projects currently reflects the best set of options for future clean coal applications?

20. Do you believe DOE's "payback" component of the solicitation has in any way dampened interest in proposing new technologies?

21. How would you characterize your state's relationship with the federal government on acid rain and/or clean coal technologies?

22. In your prepared statement, you stated quote "I am convinced that there is a very real conflict between new technology development and a headlong rush to reduce SO2 emissions pursuant to some of the acid rain proposals presently being considered". Understanding that short timetables focus control efforts on near term solutions, why is there a conflict in the future for new or repowered facilities?

23. Throughout your statement you refer to the timetables proposed in legislation. In your view, what is a realistic timetable for the introduction of clean coal technologies and subsequent reductions in SO2 and Nox?

24. You mention that by 1997, five West Virginia generating units will be 40 years or older, seven will be 30 years or older. Are any of these plants candidates for repowering with existing clean coal technology?

25. As a regulator, how far are you willing to go in increasing electric rates to consumers in order to accomodate the introduction of clean coal technologies?

26. Do you believe clean coal technologies are a viable solution to acid rain?

ENR
Illinois Department of Energy and Natural Resources

325 W. Adams Street, Room 300
Springfield, IL 62704-1892
217 785-2800

June 30, 1986

Mr. Richard Grundy
Director of Oversight and Investigation
United States Senate Committee on
Energy and Natural Resources
SH-312
Washington, DC 20510

Dear Mr. Grundy:

Attached are responses to the questions submitted to me by members of the Committee on Energy and Natural Resources following my testimony at the June 9 oversight hearings on Clean Coal Technology and acid rain control.

I appreciate the opportunity to provide additional input on these important issues.

Sincerely,

Terri Moreland

Terri Moreland
Manager/Illinois Coal
Development Programs

sm

Attachment

cc: Don Etchison
Ann Van Leer

RESPONSES TO
QUESTIONS SUBMITTED TO
TERRI MORELAND
HEARING ON
CLEAN COAL TECHNOLOGY AND ACID RAIN CONTROL

1. EPA Administrator Thomas, on behalf of the Administration, stated that,

> "we do not yet believe that the current state of knowledge can sustain any judgment with respect to the level of emission reductions needed to prevent or eliminate damage."

Do you agree with this statement?

ANSWER: I agree with the statement of Administrator Thomas.

2. EPA Administrator Thomas added,

> "this is true even for the area of greatest scientific understanding, sulfur emission and surface water acidification. In the area of the impact of acid disposition on forests, we have yet to determine if a cause and effect relationship exists."

Do you agree with this statement?

ANSWER: I agree with the statement of Administrator Thomas.

3. On the basis of current knowledge of the causes of acid rain, in your judgment, can we formulate a control strategy that will assure achievement of the intended mitigation of acid rain once the prescribed control investments have been made? In other words, can we determine what pollutants need to be controlled, the size reductions that are called for, where the reductions should take place, and over what time frame they should be implemented?

ANSWER: In my judgment, it would be impossible to predict whether the environmental damage ascribed to acid rain would be mitigated by control strategies that have been proposed, or to formulate a program that would achieve the intended mitigation. I believe that the development and application of measures to reduce environmental pollutants from all sources is a worthwhile goal to be pursued at the national level, and that productive, realistic and scientifically credible programs should be fostered to achieve this goal.

4. There has been considerable discussion of the need to place emphasis on the development of clean coal technologies with retrofit application. For example, the Special Envoys Report emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

   EPA Administrator Thomas emphasized in his testimony that "the most important application category for the focus of clean coal technology development would be the coal-fired retrofit application." Do you agree?

   a. In your judgment, does the DOE Clean Coal Technology program adequately reflect this need? Or does the program place too much priority on technologies applicable to new construction?

   b. Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control? Should they be?

   ANSWER: The development of retrofit technologies is most important from the standpoint of the acid rain debate, because of concerns about SO_2 and because a relatively large percentage of this substance is emitted from existing coal-fired power plants.

   a. In my assessment, the statutory language creating the Clean Coal Technology program within DOE gives no indication of specific Congressional intent to link the program to acid rain mitigation. Program guidelines and project selection criteria, however, include the potential for funding various types of retrofit systems applicable to existing coal-fired plants. The State of Illinois has pledged support for three retrofit technology demonstrations proposed to the DOE program.

   b. Within the established guidelines, the DOE program could fund technologies for retrofitting existing coal-fired plants, for the development of new electric utility or industrial plants, or for retrofitting existing gas- or oil-fired plants to coal use. In my judgment, all three categories of demonstration projects are worthy of program support. Both retrofit technologies that can economically control pollution from existing coal-fired plants and technologies for new sources that have economical and environmental benefits offer the potential of more effective control of SO_2 (and NO_X) in the future.

5. Under what circumstances will life-extension result in reduced atmospheric emissions?

   ANSWER: Life-extension measures which include the application of control technologies will result in reduced atmospheric emissions.

6. What is the potential that the types of clean coal technologies under discussion will be able to meet New Source Performance Standards without the use of scrubbers?

   ANSWER: I have not had access to any detailed information on projects submitted for consideration through the Clean Coal Technology program, other than those in which the State of Illinois is directly involved. Based on reports in various news publications, it appears that several technology concepts proposed are targeted at meeting Clean Air Act requirements for new sources without the use of scrubbers. These include atmospheric (fixed and circulating) fluidized-bed technologies, pressurized fluidized-bed systems, coal gasification for industrial and electric utility applications, and underground coal gasification.

7. Are the technologies being developed by the DOE Clean Coal Technology program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?

   ANSWER: Since current regulations require control of emissions from new or substantially modified sources, it is likely that new technologies will be commercially deployed without additional regulatory action if they demonstrate environmental compliance in addition to economic or operational advantages. The types of technology concepts listed in response to question #6 would be promising candidates for use in meeting future power requirements.

   Other concepts proposed for support through the U.S. DOE program represent coal processing and non-scrubber plant retrofit technologies that are not necessarily targeted to the compliance standards for new or substantially modified plants. They include advanced physical coal cleaning, chemical and microbial coal cleaning, burner sorbent injection, and furnace or duct sorbent injection, in addition to low-NO_X technologies. If these types of technologies are developed and fully proven, they may offer significantly more economical pollution control and wider applicability than the technology options currently available. It is my opinion that the promulgation of new regulatory requirements such as those currently proposed will effectively stop the development of these technologies. However, if they are given a chance to develop so that risks are reduced and costs established, new regulatory requirements can be adopted to ensure their deployment.

8. Mr. Donald Bauer, on behalf of DOE, stated that performance testing of clean coal technologies under consideration by DOE generally will not be completed until the early to mid-1990s. He concluded with the observation that "if the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options." Do you agree?

   ANSWER: I agree with Mr. Bauer's assessment.

9. One of the premises behind the Clean Air Act was that industry would gradually retire old facilities and replace them with new installations subject to "new source performance standards." Consequently, there would be a gradual improvement in air quality. In your judgment, has this occurred?

In asking this question, it is observed that EPA Administrator Thomas, commenting on plant life extension trends, stated that, "this postpones the rate at which new sources will replace existing sources, making New Source Performance Standards a less effective way of reducing overall emissions in the near or middle term."

ANSWER: In the period 1974 through 1980, SO_2 emissions in Illinois were reduced by approximately 25%. This reduction was achieved through a variety of means, including retirement of older generating stations, addition of 1306 MW in new capacity with scrubbers, fuel switching, and increased electrical generation with nuclear power.

10. In your opinion, what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the various legislative proposals before the Congress? For example, is the electric utility industry likely to rely on extension of the life of existing facilities rather than their retirement and replacement with new facilities?

ANSWER: If the proposed regulations capping emission levels at 1.2 lb. SO_2/MMBtu and 0.6 lb. NO_X/MMBtu are adopted, we estimate that Illinois utilities would be forced to shut down 6300 MW of generating capacity because there is no commercially available technology to reduce NO_X emissions from cyclone boilers to the required level. The remaining 3,667 MW of unscrubbed capacity now using Illinois coal would be forced to install flue gas desulfurization or switch to compliance coal. Given the age of many of these plants, economics would favor fuel switching.

Utilities installing FGD would probably extend the useful life of these units to reduce rate impacts and increase economic performance. Units operated on compliance coal would probably be derated rather than upgraded and used as needed in accordance with economic dispatching.

11. In your judgment, to what extent is industry's decision to extend the life of an existing facility influenced by regulatory policies? For example, as I understand EPA regulations, at a certain point the costs of retrofitting an existing facility become great enough that it runs the risk of being classified as a new one subject to New Source Performance Standards. Would you comment.

ANSWER: Economics and plant-specific factors will dictate whether significant modifications will be made to extend the life of a particular facility. It is estimated that the costs of life extension range from less than $250 to $600 (with fgd) per kilowatt, compared to new capacity costs of $1,200 to $1,500 per kilowatt.[1] I believe that life extension will be an economical alternative to replacement at many sites, whether in response to economic or regulatory issues.

12. The Clean Air Act provides for an extension of compliance dates for facilities that propose to utilize new or innovative technologies to comply with emissions standards. In your judgment, has this authority been effectively implemented by the EPA?

    ANSWER: I am aware of this provision, but I do not believe that it can be effectively implemented, unless additional incentives are offered, because of the risks and higher costs involved in first-of-a-kind demonstration projects. I believe that time extensions for compliance can potentially play an important role in the implementation of the Clean Coal Technology program for projects subject to Clean Air Act standards.

13. What is the national average cost of FGD retrofit per kilowatt? And, what would be the cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements? What would be the differential cost between implementation of the above options?

14. What, in your judgment, are the estimated costs of implementing proposed acid rain legislation? Would you indicate the sources of such cost estimates and whether you agree, or disagree, with such analysis?

    ANSWER TO 13 AND 14: According to our records, there are currently 33 retrofit FGD units in the U.S., with various SO_2 removal efficiencies. Costs of these systems ranged from $18 per KW to $282 per KW in 1978 dollars. Estimates, in 1986 dollars, for plants that are most likely candidates for retrofit range from $275 to $350 per KW.[2] There are so many variable constraints that it would be extremely difficult to determine the costs of retrofitting all existing coal-fired facilities to meet a uniform standard. However, a Temple, Barker and Sloane, Inc. analysis of acid rain strategies estimates 15-year costs of $86 billion for scrubbing the 50 plants with highest SO_2 emissions, and $110 billion for emission-specific reductions to meet current acid rain legislation.[3]

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[1] "A Strategy for Fossil Power Plant Life Extension", A.F. Armor, J.R. Sheibel and J.B. Parkes, American Power Conference, April 1985.

[2] "Evaluation of HR 3400, The 'Sikorski/Waxman' Bill for Acid Rain Abatement', Temple, Barker & Sloane, Inc., September 20, 1983. Updated to 1986 dollars.

[3] "Economic Evaluation of H.R. 4567, The 'Acid Deposition Control Act of 1986'", Temple, Barker and Sloane, Inc., April 14, 1986.

It should be noted that these estimates represent only those costs that would be borne by electric utility ratepayers. We have estimated that in Illinois alone, proposed acid rain legislation could result in losses of $1.3 billion annually in coal sales and $.9 billion in direct and indirect economic benefits (1986 dollars).

15. What, in your judgment, are the comparative roles of different source contributors of air pollution as contributing factors in acid precipitation? Would you indicate the sources of such information and whether you agree, or disagree, with such analysis?

    ANSWER: There are many uncertainties and unknowns involved in this issue, and the data and information available at this time remain conflicting and subject to a wide range of interpretations.

16. In your view, is it realistic to expect emerging clean coal technologies to significantly contribute to SO_2 and NO_X reductions prior to the year 2000?

    ANSWER: There are several promising clean coal technology concepts that could be ready for commercial use prior to the year 2000, if adequate support is given to their development. The rate at which such technologies will be adopted will depend on a variety of factors, including demand for new capacity, regulatory decisions, relative fuel costs, and national energy use patterns. These factors, in turn, will influence whether significant reductions in SO_2 and NO_X will occur through the use of clean coal technologies prior to the end of this century.

17. From your state's perspective, would you prefer to operate a clean coal technology program, or continue to operate under a federal program?

    ANSWER: We do not currently operate under a federal program. The State of Illinois has operated its own clean coal technology demonstration program since 1977, based on objectives set by the Illinois Department of Energy and Natural Resources, and we expect this program to continue. Several of our demonstration projects have involved co-funding by the federal government. Our Governor, James R. Thompson, and the Illinois congressional delegation have been active in seeking a sustained, adequately-funded Clean Coal Technology program at the federal level. We believe that this program will speed the development and commercialization of advanced coal technologies and promote a far wider range of technical options than would be possible through individual state programs.

18. Each of your states have a strong interest in seeing coal developed to a greater degree. Does this interest mitigate against state efforts toward SO_2 and NO_X reduction?

ANSWER: Nearly all of Illinois' coal development programs and related project activities are aimed at the research, demonstration or commercial deployment of clean ways to use coal. In addition, Illinois' environmental regulations governing the use of coal are in some cases more stringent than the applicable federal regulations.

19. Having an interest in DOE's solicitation on clean coal technologies, do you believe the range of projects currently reflects the best set of options for future clean coal applications?

    ANSWER: While I am generally pleased with the scope of technology concepts proposed to DOE, I believe that additional concepts of merit would be advanced by the release of the $350 million remaining in the Clean Coal Technology Reserve.

20. Do you believe DOE's "payback" component of the solicitation has in any way dampened interest in proposing new technologies?

    ANSWER: The payback component has discouraged projects that do not generate revenues.

21. How would you characterize your state's relationship with the federal government on acid rain and/or clean coal technologies?

    ANSWER: We believe that the federal government's approaches to these issues are reasonable and appropriate.

22. You mention in your statement that Illinois has provided $55 million for clean coal technologies. Has the state focused on particular technologies or has the funding been more broad-based?

    a. Could you comment on specific projects outside of those mentioned in your statement?

    b. Promising research funded by the state?

    ANSWER: The amount, now totalling over $62,000,000, which the State of Illinois has invested in clean coal technologies to date has included funding for basic and applied research, partial support for technology demonstration projects, and low-interest loans for the commercial application of proven technologies. We have worked for the development of technical options suitable for a wide range of applications.

    a. State-funded demonstration projects include advanced boiler systems, coal gasification, and flue gas desulfurization technologies. State commitments to these projects total $50,350,000. Specific projects are outlined in Attachment A.

    b. The State of Illinois has maintained a program of fundamental and applied research since 1981. The principal objective of this program is sulfur abatement. Approximately $10,000,000 in state funds have been committed to the program to date. The current level of funding for sulfur-related research is approximately $2,500,000 annually.

Illinois' sulfur research program involves the participation of public and private research institutions in Illinois and nationwide. Individual projects are managed and coordinated through the Department of Energy and Natural Resources' Center for Research on Sulfur in Coal.

The Center for Research on Sulfur in Coal is currently involved in a number of projects that are aimed at furthering new sulfur removal processes in the near- to mid-term. The following are a sample from over 30 active state research projects.

- Aggregate Flotation Fine Coal Cleaning Process (Illinois State Geological Survey): The principal goal of this research is to develop a new fine-coal cleaning approach that can operate more efficiently and less expensively than those commercially available. The process involves pretreatment of fine coal with a small amount of kerosene prior to agitation with a commercial foaming surfactant and air. The resulting aggregates of clean oil-coated coal particles can be removed by mechanical means.

  An associated goal of this project is to assess the practical (or ultimate) physical cleanability of Illinois coals of fine particle sizes, similar to those produced in volume in modern mechanized mining operations. This is being done through the use of petrographic, mineralogic, and chemical analysis procedures that characterize pyritic sulfur, ash, and other constituents.

- Process Model Development for Simulation of Fine Cleaning of Illinois Coals (Northwestern University): The focus of this project is on nearer-term technologies as opposed to those using exotic coalescing agents. The overall goal is to provide an economical means to estimate the techical limits of current and emerging agglomeration and flotation processes for Illinois coals. The resulting mathematical models will facilitate the optimization of coal cleaning process specifications for various coals and operating conditions.

- Studies of SO_2 Removal During Pulverized Coal Combustion by Injecting Limestone (University of Illinois-Urbana): Although limestone injection is known to reduce SO_2 emissions, optimal process design strategies require quantification of mixture ratios, mixing times, particle sizes and temperature. The goal of this project is to study these variables and their effects on the efficiency of sulfur conversion to $CaSO_4$ using an Entrained Dust Flow Combustor (EDFC). A theoretical model will be used to aid in the interpretation of the EDFC data.

23. How successful has your state's program of encouraging retrofit with low-interest loans for fluidized bed systems been?

    a. What percentage of the coal-fired use in Illinois been affected by these low-cost loans?

    b. What is the scope of the program? Funding levels?

    ANSWER: Illinois' low-interest loan program for industrial clean coal technologies is part of Governor James Thompson's recent "Build Illinois" initiative. Final program approval was received in March, 1986. Because the program is so new, its success has not yet been determined.

    a. To date, the state has committed $2,500,000 in low-interest loan funds for the installation of two coal-fired circulating fluidized-bed boilers at the A. E. Staley Manufacturing plant in Decatur, Illinois. This new boiler installation will use 380,000 tons of coal per year. This represents 12.5% of total industrial coal consumption in Illinois.

    b. The program is conceived as a five-year, $55,000,000 initiative. Loans will be repaid into a revolving fund to assist in the financing of additional conversions after the five-year startup period. For state fiscal year 1987, a total of $12,000,000 in program authorization is anticipated.

24. An apparent problem for using clean coal technologies to mitigate acid rain is the timetables assumed to be required for reductions in SO_2 and NO_X. In your view, what is a reasonable time frame for SO_2 and NO_X reduction? And secondly, which clean coal technologies are likely to be most readily available within that time frame?

    ANSWER: The time frame for SO_2 and NO_X reductions achieved through clean coal technologies will, as stated earlier, depend on numerous and complex factors. I believe that, with adequate support, some technologies can be sufficiently developed for commercial use by the mid- to late-1990's. These technologies vary in SO_2 and/or NO_X removal efficiencies, projected cost-effectiveness, suitability for specific applications, and current stage of development. I would include advanced coal preparation, coal gasification/combined cycle, advanced combustors, atmospheric and pressurized fluidized-bed boilers, advanced wet and dry flue gas desulfurization, and sorbent injection technologies in this near- to mid-term category.

25. Which technologies are, in your view, most economical for retrofit?

ANSWER: Advanced coal preparation, while not limited to retrofit applications and not recognized as a sulfur control strategy under current regulations, is generally assumed to be the most cost-effective sulfur control option. Indications are that sorbent injection systems offering 40 to 60% sulfur removal capability will provide cost-effective emission control. These are often envisioned in combination with relatively economical low-NO_X combustion systems.

26. Do you believe clean coal technologies will actually allow us to increase coal utilization?

ANSWER: Clean coal technologies will increase coal utilization to the extent that they stimulate the replacement of other fuels with coal.

ATTACHMENT A

STATE OF ILLINOIS DEMONSTRATION PROJECTS

1. Project Type: Atmospheric Fluidized-Bed Boiler

Location: Great Lakes Naval Station
Great Lakes, Illinois

Date Approved: July, 1977

Project Sponsors: U.S. Department of Energy
Combustion Engineering, Inc.
State of Illinois
U.S. Navy

Total Project Cost: $27,020,962 (includes $6,802,393 in R & D costs)

State of Illinois Funding: $750,000

Summary Description: This project featured a first-generation fluidized-bed boiler developed by Combustion Engineering Power Systems. The 60,000 lb./hr. demonstration boiler was conceived as a prototype for commercial units that could be shop-assembled and shipped by rail to industrial users. It was designed to use high sulfur coal with a high level of pollution control, while meeting industrial requirements for efficiency, quick response and maximum load-following capability.

Project construction was completed in 1981. Testing and operation of the boiler, which continued through the spring of 1984, demonstrated 92 percent sulfur capture, 93 percent combustion efficiency, and nitrous oxide emissions of approximately half the regulatory limit. The boiler showed excellent combustion stability and was capable of meeting load changes of up to 3 percent per minute. In addition, the project provided information on such important factors as coal feed system design, boiler tube configuration and limestone use.

2. Project Type: Low-Btu Coal Gasification (KILnGAS)

Location: Illinois Power Wood River Station
East Alton, Illinois

Date Approved: February, 1979

Project Sponsors: Allis-Chalmers Corporation
Consortium of Twelve Utilities
State of Illinois
U.S. Department of Energy
Electric Power Research Institute

Total Project Cost: $232,100,000 (estimated, includes operating costs)

State of Illinois Funding: $35,850,000

Summary Description: This project is aimed at the production of a clean low-Btu gas from high sulfur coal for direct combustion as a utility boiler fuel or use in combined-cycle applications. The major component of the project is the KILnGAS Commercial Module, a pressurized, ported rotary kiln gasification system developed by the Allis-Chalmers Corporation. The system is designed for high carbon conversion efficiency and load-following capability. The KILnGAS demonstration plant is capable of processing 600 tons of coal per day, producing 409 million Btu/hour of clean gaseous fuel. Product gas is burned in an existing Illinois Power Company Boiler to generate approximately 37 megawatts of electricity.

Project construction was completed in 1983. The gasification plant has completed performance testing and demonstration, and is now in the second phase of an extended Reliability, Availability and Maintainability program. This program is intended to demonstrate process modifications, verify operating parameters and establish a data base for full-scale installations.

3. Project Type: Circulating Fluidized-Bed Boiler

Location: BFGoodrich Chemical Group Plant
Henry, Illinois

Date Approved: June, 1982

Project Sponsors: BFGoodrich
State of Illinois

Total Project Cost: $21,300,000 (estimated)

State of Illinois Funding: $4,300,000

Summary Description: This project demonstrates a Pyroflow circulating fluidized-bed boiler, developed by the Pyropower Corporation, for the production of process steam. The boiler is sized to produce 125,000 pounds of steam per hour. The circulating fluidized bed is designed to attain higher combustion efficiency and limestone utilization than conventional fbc technologies through high turbulence and circulation of solids in the system.

Project construction was completed in August, 1985 and performance testing was completed in May, 1986. Results indicated boiler efficiency of 85.1%, combustion efficiency of 98% and emissions well below Illinois Environmental Protection Agency standards for industrial boilers. The plant is now undergoing a three-year demonstration program.

4. Project Type: Atmospheric Fludized-Bed Boiler

Location: Midwest Grain Products Company of Illinois
Pekin, Illinois

Date Approved: October, 1982

Project Sponsors: Midwest Grain Products Company
State of Illinois

Total Project Cost: $12,265,714 (actual)

State of Illinois Funding: $2,500,000

Summary Description: The demonstration system is based on a 120,000 pound/hour Foster Wheeler fbc boiler with design innovations aimed at reliability, efficiency and ease of operation. The system provides all of the process steam and cogenerates most of the electricity needed at the Midwest Grain Products facility.

Construction of the plant was completed in May, 1984. The boiler has now logged over 17,000 hours of operation. Plant availability has exceeded 90%, with excellent boiler efficiency, environmental performance and load-following capability. A three-year demonstration program is now underway.

5. Project Type: Advanced Wet Flue Gas Desulfurization

Location: Abbott Power Plant
University of Illinois
Champaign, Illinois

Date Approved: October, 1982

Project Sponsors: State of Illinois
Electric Power Research Institute

Total Project Cost: $10,000,000

Coal Development Program Funding: $4,950,000

Summary Description: This project will demonstrate the CT-121 flue gas desulfurization system, developed by the Chiyoda International Corporation. The CT-121 is a highly advanced limestone scrubber system designed for reliable performance, low operating and maintenance costs and effective control of pollutant emissions. It utilizes one major reactor vessel, a patented liquid-gas contacting device in which the sulfur dioxide in the boiler flue gases is absorbed and converted into commercial-grade gypsum. The pure gypsum byproduct is less polluting and easier to manage than the wet sludge produced by conventional limestone scrubbers and can potentially be sold for use in the manufacture of wallboard or cement.

Project construction was initiated in May, 1985 and should be completed in August, 1986.

6. Project Type: Dual Fluidized-Bed Boiler Retrofit

Location: Anderson Clayton Foods Division Plant
Jacksonville, Illinois

Date Approved: January, 1985

Project Sponsors: Anderson, Clayton & Company, Inc.
State of Illinois

Total Project Cost: $5,000,000 (estimated)

State of Illinois Funding: $1,000,000

Summary Description: This project will demonstrate the Wormser Grate Dual Fluidized-Bed Boiler, developed by Wormser Engineering, to retrofit existing gas- or oil-fired boilers to coal use.

While most fbc systems utilize a single combustion chamber in which the coal and limestone are mixed, the Wormser Grate system uses two shallow beds, one above the other, to provide optimal temperature conditions for combustion and pollution control. In this project, the Wormser Grate is being installed adjacent to an existing gas- and oil-fired boiler. Clean gases leaving the Wormser Grate will be ducted to the boiler, which will act as a waste heat boiler to produce approximately 40% of overall steam capacity. The total system will produce a nominal 70,000 pounds of steam per hour with a maximum of 85,000 pounds per hour.

Plant construction was begun in July, 1985 and completed in June, 1986.

7. Project Type: Dry Regenerable Flue Gas Clean-Up

Location: Commonwealth Edison Kincaid Power Station

Date Approved: June 2, 1986

Project Sponsors: U.S. Department of Energy
State of Illinois
UOP, Inc.

Total Project Cost: $7,600,000

State of Illinois Funding: $1,000,000

Summary Description: This project will demonstrate a 10,000 scfm (5 MW equivalent) proof-of-concept fluidized-bed copper oxide unit. The technology was developed by the U.S. Department of Energy. The process utilizes a fluidized-bed absorber containing small alumina spheres impregnated with copper oxide. The sulfur dioxide in boiler flue gases is absorbed on the spheres, forming copper sulfate. The spent sorbent can be continuously removed and regenerated by driving off the sulfur dioxide, which can then be converted to saleable sulfuric acid or elemental sulfur. Nitrogen oxides in the flue gases will be removed by ammonia injection. The copper oxide/sulfate spheres act as a catalyst to enhance this chemical reaction.

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CLEAN COAL TECHNOLOGY DEVELOPMENT AND STRATEGIES FOR ACID RAIN CONTROL

TUESDAY, JUNE 10, 1986

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 10 a.m., in room SD-366, Dirksen Senate Office Building, Hon. James A. McClure, chairman, presiding.

Present: Senators McClure, Warner, Murkowski, Hecht, and Ford.

Also present: Richard D. Grundy, director of oversight and investigations; Jeffrey Arnold, professional staff member; and Elizabeth Moler, James T. Bruce, and Patricia Beneke, counsels for the minority.

OPENING STATEMENT OF HON. JAMES A. McCLURE, A U.S. SENATOR FROM THE STATE OF IDAHO

The CHAIRMAN. The committee will come to order.

Today we conclude 2 days of oversight hearings on the relationship between the development of clean coal technologies and strategies for acid rain control.

Yesterday we received testimony from administration witnesses and representatives of the States. Today's witnesses are individuals with a direct interest in the development of clean coal technologies, either as producers or users of coal or as representatives of the environmental community.

Few disagree that the popular term acid rain describes a very complex phenomenon of atmospheric chemistry that is very poorly understood. Similarly, few would disagree that we cannot be assured that the strategies being proposed for acid rain mitigation will achieve the intended environmental benefits even though accompanied by significant economic cost. Uncertainty thus exists regarding what actions would be taken by a prudent person to achieve the intended goals for the mitigation of acid precipitation.

Environmental benefits are to be achieved from the control of acid rain, but how they are achieved has significantly different social and economic consequences for different parts of America. An acid rain control strategy that encourages extension of the life of existing installations will have considerably different long-term energy, environmental and economic consequences than a controlled strategy that relies on construction of new clean coal technologies.

For example, if the Congress adopts a control strategy premised on life extension, then the clean coal technology development program that emphasizes new construction runs the risk of demonstrating control technologies which no one will be in a position to use.

As I stated yesterday, these hearings are being held because of the concern of this Senator and others for the apparent dichotomy between the development of acid rain control policy and the development of new clean coal technologies.

Hopefully today's witnesses will provide the committee with their unique insights on appropriate national policies that reflect the interrelationship between energy and environmental policies.

We will start with a panel: Mr. Richard E. Disbrow, president, American Electric Power; John McCormick, Environmental Policy Institute; and Gene Mannella, director of the Washington office of EPRI.

The first witness, Mr. Disbrow.

STATEMENT OF RICHARD E. DISBROW, PRESIDENT, AMERICAN ELECTRIC POWER CO., INC., ON BEHALF OF THE CLEAN COAL TECHNOLOGY COALITION

Mr. DISBROW. Good morning, Mr. Chairman. I am Richard E. Disbrow, president, American Electric Power.

The CHAIRMAN. I should say at the outset that your three prepared statements will be placed in the record, and you are invited to summarize, if you will.

Mr. DISBROW. I appear today on behalf of the Clean Coal Technology Coalition, which is comprised of utilities, coal companies, equipment suppliers, architect engineering firms, State governments, the National Coal Association, and the Edison Electric Institute. The purpose of the coalition is to support and encourage the development of emerging clean coal technologies and their subsequent deployment.

At the outset, Mr. Chairman, let me compliment the committee for conducting these oversight hearings and express our appreciation to you and other members of this committee for your past support and leadership in launching the clean coal initiative and the program of Federal cost sharing.

The Clean Coal Technology Demonstration Program has already accelerated industry's efforts to commercialize an array of options to better use our Nation's abundant coal supply. These efforts by the private sector and Government have now placed us at the threshold of a new generation of technologies which could easily foster the expanded use of coal in both a cost effective and environmentally acceptable manner.

What we need most is time; time to get the job done. I am submitting a detailed statement setting forth the coalition's views, but recognizing the broad scope of these oversight hearings and in the interest of brevity I will confine my oral remarks to four issues:

First, the role of clean coal technology development in meeting the Nation's environmental and energy objectives and in a cost effective manner;

Second, the probable effects on such development if acid rain control legislation is enacted;

Third, the potential impact on the economy; and

Fourth, recommendations that would enhance a successful clean coal demonstration and deployment program.

Accelerated development of promising technologies will increase the range of options for new plant construction which will be needed by the mid-1990's and beyond to meet the growing demand for electric energy and to replace equipment reaching the end of its useful economic life.

Such technologies as atmospheric and pressurized fluidized bed combustion and coal gasification, among others, will provide alternatives to conventional pulverized coal units with their federally mandated scrubbers.

Permit me to use pressurized fluidized bed combustion as an illustration. Why? Because our company is pursuing this alternative, and I am most familiar with it. By burning a mixture of coal and dolomite under pressure and using a combined cycle with gas and steam turbines, plant efficiency will be increased, resulting in less coal burned per unit of output.

Ninety percent of SO_2 emissions or more will be eliminated, and the by-product will be a dry, easily handled calcium sulphate. Low combustion temperature results in much lower NO_x emissions than present-day standards. The PFBC technology also is capable of unparalleled fuel flexibility. Any quality of coal can be used.

Furthermore, the design is modular, permitting significant factory fabrication and therefore less field labor, construction time and construction cost. In addition, it can be constructed in relatively smaller modular increments to limit total financial commitment while better matching actual load growth requirements with the amount of new capacity being brought on line. A similar favorable analysis could be offered for other clean coal technologies under development.

Retrofit technologies are now also under development and are of major importance for application where feasible. The reduced SO_2 and NO_x emissions from existing plants, the LIMB process and induct scrubbing are representative of these technologies which, if found to be cost effective, will be particularly useful.

Decisions to extend plant life are determined by comparing the capital cost of refurbishing the facility with the estimated remaining useful life of that facility. Where successfully retrofitted with a cost effective clean coal technology, an existing facility could attain the dual goals of continued reliable energy supply and reduced emissions.

It now appears, however, that most of the retrofit technologies under consideration do not attain new source performance standards. Consideration should be given, therefore, to modifying existing EPA regulations to allow for the deployment in plant life extended situations of clean coal retrofit technologies capable of, say, 40 to 50 percent emission reduction.

If existing standards tend to frustrate promising retrofit technologies, passage of acid rain control legislation which mandates major near-term reduction in NO_x and SO_2 emissions would stifle all clean coal technology development.

The capital requirements with the proposed acid rain control legislation are overwhelming, and inevitably any funds available for new technological development would be siphoned off to insure compliance with the regulatory program. Many existing plants might have to be closed on the basis of economic consideration, possibly bringing the reliability of today's electric energy supply into question and surely raising a serious concern over our industry's ability to construct new facilities for tomorrow's needs.

Immediate reductions would require the use of scrubbers. Once we commit the scrubbers, it will not make economic sense to later convert and use a new clean coal technology. Additionally, from an energy perspective the ratepayer will be committing to a never-aging and less efficient generating system.

Clean coal technologies will not be available for utilization before proposed major emission reductions are required. The demonstration of new technologies takes time, and even if we successfully demonstrate, for example, our pressurized fluidized bed technology by the early 1990's, which is our current accelerated development timetable, we will be unable to commit plant and incorporate this technology into our system much before the turn of the century.

The development path of other technologies is very similar. We need time to build demonstration projects and adequately test the technologies.

The point I make is very simple, Mr. Chairman. We cannot proceed in two directions at once. If massive emission reductions are mandated for the early 1990's, clean coal technologies simply cannot be accelerated to meet that timetable.

From the point of view of the national economy, the orderly development and deployment of clean coal technologies is far more preferable than immediate retrofit using scrubber technology. Cost effective technologies for new source and retrofit applications can be deployed with minimum impact on consumers' bills.

The alternative of a mandated regulatory program which will force the use of existing technology will result in what has become known as rate shock. When you impose such cost upon our battered midwestern industrial base, you also invite serious economic dislocations. American manufacturers struggling to compete in the international marketplace do not need the added burden of sharp increases in the cost of electric energy.

To encourage the development of the full range of clean coal technologies, we urge the committee to consider the need to provide additional cost sharing assistance in order to further demonstrate retrofit technologies, repower or modernize existing facilities.

Given the significant uncertainties currently facing the utility industry, it is clear that many are examining the extension of existing plant lives as an alternative to new capacity. If other market or regulatory forces are compelling the continued use of older facilities, then it is important to develop those technologies, which not only enable greater reliability of service but also insure decreased emissions.

Another DOE statement of interest solicitation would determine the degree of industry interest. If sufficient interest exists, Congress should make available $350 million already authorized in the clean coal technology reserve.

The Congress and the administration should also immediately examine the extent to which regulations must be changed and other financial incentives enacted to insure the deployment of technologies once demonstrations are completed. Anything accomplished today to eliminate regulatory or financial uncertainty will better insure the widespread use of commercially demonstrated technologies tomorrow. We will be pleased to work with you and your staff on this important requirement.

Finally, if despite the absence of scientific support acid rain legislation is to be given further consideration, please focus upon the timetable of any mandated reductions. The full range of emerging clean coal technologies cannot be developed and deployed within the timetables for mandatory reductions now under discussion.

We need support from the Federal Government to share in the risk of development, and we need time to perfect and then to deploy these new technologies. We can do it.

Mr. Chairman, we believe clean coal technologies are an appropriate response for meeting environmental and energy objectives, not for the sake of the electric utilities, the coal suppliers and others of the coalition I represent but rather for the sake of the American consumer that we both are privileged to serve.

Thank you.

[The prepared statement of Mr. Disbrow follows:]

HEARINGS BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
WRITTEN STATEMENT OF
RICHARD E. DISBROW
PRESIDENT
AMERICAN ELECTRIC POWER COMPANY, INC.
JUNE 10, 1986

INTRODUCTION:

This statement is submitted by American Electric Power Company, Inc., on behalf of the Clean Coal Technology Coalition. The Coalition is an ad hoc group of utilities, equipment suppliers, coal companies, architect-engineering and construction firms, several state governments, the National Coal Association and the Edison Electric Institute.

AEP is an electric utility holding company with eight operating companies. The AEP system includes twenty-two major power plants, with principal customer load centers tied together by more than 22,000 miles of high-voltage transmission circuits. Twenty of AEP's twenty-two large generating stations are coal-fired. On average, year in and year out, close to ninety percent of AEP's electricity generation comes from coal. AEP produces and sells more than 100 billion kilowatt hours a year, providing reliable electric service to more than seven million people in an area of 48,000 square miles extending over parts of seven East-Central states.

AEP's commitment to coal as a primary source of energy spans eight decades. Eighty years of extensive research and development efforts -- particularly the last decade of carefully formulated development work, including coal cleaning -- are culminated in AEP's PFBC Development program. The success of our program is expected to permit commercial deployment of PFBC combined cycle technology in the United States by the mid-1990's, with direct application at same size units (80 MW) as the Tidd PFBC Demonstration Plant and scale-up to larger size modules (320 MW) at a low risk. We and our partners have spent over $40 million to date bringing this technology to the stage where it is ready for commercial demonstration. To demonstrate it at commercial scale, we have estimated program costs of $218 million. We have capped our request to $10 million from the State of Ohio, and $60.2 million from the U.S. Department of Energy. AEP will put forth $105 million in new monies plus additional in-kind contributions toward the project and will absorb any additional costs should the project costs exceed our estimates.

On behalf of the members of the Coalition, I wish to commend the Senate Energy and Natural Resources Committee for conducting these oversight hearings on clean coal technology development and on the possible impacts to that development should an acid rain control program be enacted. We hope that these hearings will assist the Congress in focusing attention not only on the need to reduce emissions but also on the need to provide reliable and least-cost energy to American consumers.

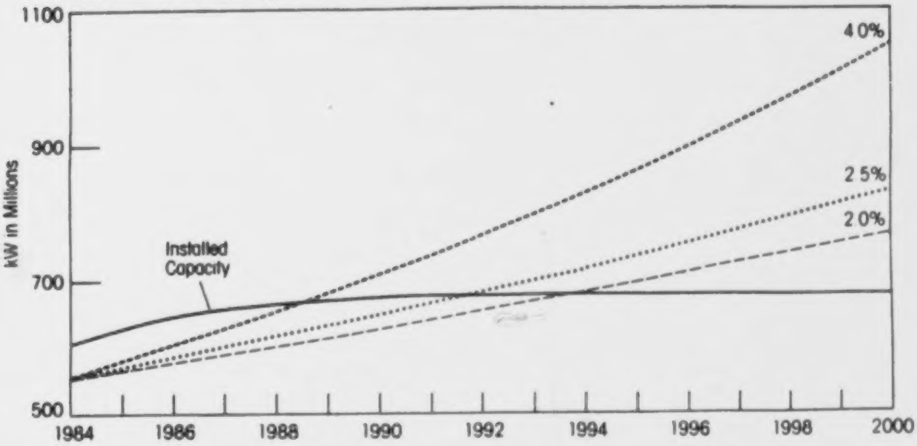
Clean coal technologies could play a major role in the future of the electric utility industry, the United States coal industry and that of other users of coal. Quite clearly, such technologies, if successfully demonstrated, will greatly advance the national goals of utilizing an immense domestic energy resource in an environmentally-acceptable manner, while providing electric utility customers and industrial users of coal with a more secure energy supply at reasonable prices.

THE ROLE OF COAL AND EMERGING CLEAN COAL TECHNOLOGIES:

Coal represents a major domestic resource upon which we can base the Nation's energy future and move toward energy independence. This major fossil fuel resource provides about sixty percent (60%) of our electricity today and, based upon the planned reduction in oil and gas use and the uncertainty of nuclear energy, coal appears to be the fuel that will be called upon to provide up to seventy percent (70%) of total U.S. electricity generation by the end of this century. It is within this context of the ever-growing reliance upon coal that the clean coal technology development program plays its pivotal role.

While there has been much disagreement over projected growth rates of electricity, the Edison Electric Institute has projected that for an annual growth rate of 2.5 percent, sometime in the early to mid-1990's peak electricity demand is expected to exceed installed capacity and new capacity above what is already planned will be required (see chart below).

U.S. Electric Generating Capacity and Peak Demand, 1984-2000



Note: Peak demand at stated growth rates with 20% capacity margin needed for dependable supply. Includes existing capacity and capacity under construction less retirements of 15 million kilowatts through 1993 as reported to NERC.

The generating capacity currently installed or assured of construction is likely to support an average growth rate in electricity demand of less than one percent per year over the remainder of this century. If demand requirements keep pace with economic growth, then an increase in demand at a modest 2.5 percent growth rate is not unreasonable. At that rate, the U.S. will still require 100,000 to 200,000 megawatts of additional new capacity this century. Most of this capacity is likely to be fueled by coal.

New Generating Capacity:

If the projected capacity needs of the mid-1990's are to be met with conventional generating units that take from seven to ten years to design, permit, construct and place in service, utilities must undertake those new powerplants now. Current trends in the utility industry strongly suggest that these new capacity requirements may not be built in time to meet this increased demand. At least part of the concern that new capacity requirements may not be met is premised upon the significant unknowns which face the industry. These unknowns include: possible additional environmental legislation and environmental regulation which might impact the continued service of existing units; further nuclear deferments; oil supply interruptions; and, the yet-to-be-proven ability concurrently to increase both the availability and life of existing capacity and the success of further conservation, load management efforts and other demand-reducing programs.

Added to these uncertainties is the fact that many utilities have cancelled or abandoned the construction of large base load facilities and are now unlikely to undertake major new construction programs. Also, new demand and therefore new capacity requirements for many utilities are likely to come in much smaller increments which may not warrant construction of large-scale conventional powerplants. And finally, because the growth of electricity demand has slowed considerably, any miscalculations by utility planners in projecting demand could result in excess capacity being built. The cost of such capacity cannot be easily recovered in rate proceedings. These and other circumstances cause utilities to be ever more cautious in adding capacity.

Accelerated development of promising technologies will increase the range of options for new plant construction which may be needed in the next decade and beyond. Such technologies as atmospheric and pressurized fluidized bed combustion and coal gasification, among others, will provide alternatives to today's conventional pulverized coal units with their Federally-mandated flue gas scrubbers.

Pressurized fluidized bed combustion, like the project submitted to DOE by AEP under the current clean coal solicitation, is an illustration of the promise which many emerging clean coal technologies hold for the utility industry and industrial consumers of coal. By burning a mixture of coal and dolomite under pressure and using a combined cycle with gas and steam turbines, plant efficiency will be increased resulting in less coal burned per unit of output. Ninety percent of SO2 emissions will be eliminated, and the by-product will be a dry, easily-handled, calcium sulfate. Low combustion temperature results in much lower NOx emissions than present-day standards. The PFBC technology also is capable of unparalleled fuel flexibility. Any quality of coal can be used. Furthermore, the design is modular permitting significant factory fabrication and, therefore, less field labor, construction time and costs. In addition, modular construction of PFBC generating plants will permit utilities to economically add smaller increments of capacity as needed. Controlled, modular expansion can be utilized to better match load growth and reduce utility financing requirements. A similar, favorable analysis could be offered for other clean coal technologies under development.

The point is that the new, emerging clean coal technologies hold great promise for providing users of coal with much more efficient options by which to provide electricity and energy.

Retrofitting Existing Capacity:

In addition to new capacity requirements in the 1990's, there is also growing awareness within the utility industry that the extension of plant life can be far less costly and less risky than embarking upon a program to build replacement capacity. Certain emerging clean coal technologies, like the LIMB process, other dry sorbent injection processes, and in-duct scrubbing, are representative of technologies which, if found to be cost effective, could be particularly useful in plant life extension programs.

The potential for extended refurbishment of fossil-fuel fired plants in meeting future load demand projections is underscored by Electric Power Research Institute (EPRI) estimates that some 55,000 MW of coal-fired and 40,000 MW of oil/gas capacity will exceed 40 years of age between now and the year 2000. Many of the units being considered for life extension now use coal for power generation.

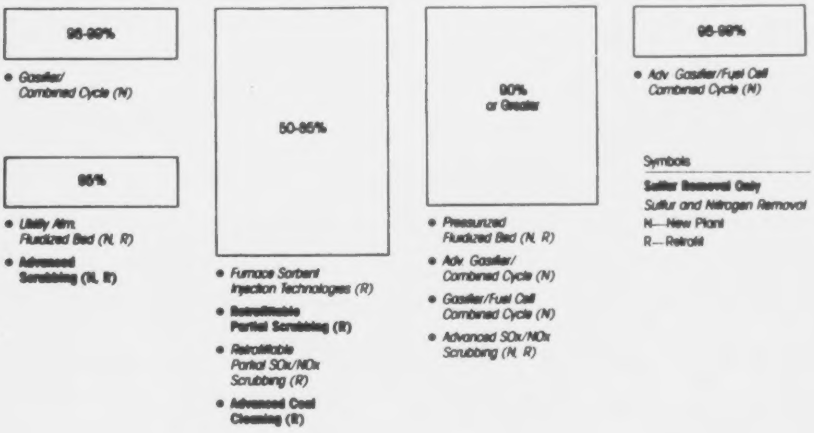
The decision by utilities to implement extended refurbishment depends on a variety of complex factors, including reserve margins, financial condition, load growth estimates, size, condition, age, fuel use and heat rates of the units under consideration. Not all aging capacity is expected to be life extended even if technically feasible to do so. Nonetheless, from a financial perspective, EPRI has estimated that refurbishment is attractive because new unit construction costs now range from 1200$/kW to 2000$/kW. In contrast, according to EPRI, extending the life of existing units for an additional 10 to 25 years by refurbishment may be achievable for 150$/kW to 300$/kW coupled with more intensive diagnostic and planned maintenance efforts during the extended life period. These costs may be justified if the desired availability can be confidently maintained for the additional period of life extension desired.

It should be noted that the utility industry has had little experience to date with extended refurbishment and, potentially, a number of unforeseen problems may surface that could drive capital and other costs much higher. In addition, considerable uncertainty surrounds the extent to which life extension efforts may invoke the imposition of environmental regulation. As provided by Environmental Protection Agency regulations governing the reconstruction of existing facilities (see: 40 CFR 60.15) "if the fixed capital cost of the new components exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility" the unit may be required to meet NSPS for SO2, NOx and particulates. Just to install the SO2 controls with a flue gas scrubbing system could increase costs by as much as $250 per kilowatt. The prospect of tripping the regulatory NSPS requirement, where the economic life of a unit has nearly ended, obviously invokes serious considerations militating against proceeding even where it otherwise may appear to be in the best interest of the ratepayers.

THE NEED TO PROTECT AND ENHANCE THE ENVIRONMENT:

Beyond the need for additional capacity in the 1990's, coal use will be paced by our ability to protect the environment. This is, perhaps, where emerging technologies will provide the greatest beneficial impact. Conventional coal fired powerplants can comply with current and proposed environmental requirements by installing scrubbers, but the dollar costs are very high. In addition to being costly, scrubbers are not always reliable and generate large volumes of wet waste as an undesirable by-product. Further, scrubbers use a significant percentage of a powerplant's electricity simply to operate and they are capable of controlling only sulfur dioxide emissions. Many new technologies are capable of controlling more than just one pollutant stream (see chart).

Emerging Technologies for SO_2/NOx Removal Potential


98-99%
Gasifier/ Combined Cycle (N)
95%
Utility Atm. Fluidized Bed (N, R)
Advanced Scrubbing (N, R)
50-85%
Furnace Sorbent Injection Technologies (R)
Retrofittable Partial Scrubbing (R)
Retrofittable Partial SOx/NOx Scrubbing (R)
Advanced Coal Cleaning (R)
90% or Greater
Pressurized Fluidized Bed (N, R)
Adv. Gasifier/ Combined Cycle (N)
Gasifier/Fuel Cell Combined Cycle (N)
Advanced SOx/NOx Scrubbing (N, R)
98-99%
Adv. Gasifier/Fuel Cell Combined Cycle (N)
Symbols
Sulfur Removal Only
Sulfur and Nitrogen Removal
N—New Plant
R—Retrofit

The timely development of these new coal utilization technologies would seem to be a far superior option to the current generation of scrubbers.

By also achieving significant reductions in emissions of multiple, not individual, pollutants, new clean coal technologies appear to be a far more productive use of scarce investment dollars.

CURRENT STATUS OF THE CLEAN COAL TECHNOLOGY PROGRAM:

Congress, particularly Members of the Senate Energy and Natural Resources Committee, recognized the need for the Federal government to assist in the accelerated development of clean coal technologies by enacting last year the $750 million clean coal technology development program. In response to a Department of Energy solicitation requesting proposals for clean coal technology demonstration projects, fifty-one submittals were made to the DOE in April, 1986. The Department has since informed the Congress that thirty-nine of those proposals met the initial evaluation criteria and are now being examined. Initial selections will be made by August 1, 1986, if the DOE remains on the schedule mandated by law.

The Clean Coal Technology Coalition has not made a thorough analysis of the proposals submitted. Information available to the public is modest and limited to abstracts of projects prepared by the proposers. However, of the submittals made there appears to be few retrofit projects proposed. The development of these retrofit technologies is important, as noted previously in this statement, as utilities consider which, if any, aged or aging facilities might be maintained in service for a longer period of time.

Why specific entities did not propose projects to demonstrate retrofit technologies is a subject of speculation. However, one important factor may well have been that there is considerable regulatory uncertainty about the eventual commerical utilization of some clean coal retrofit technologies. American Electric Power has proposed the demonstration of a pressurized fluidized bed technology. One of the reasons for that choice is that the PFBC technology will be capable of meeting new source performance standards for both SO2 and NOx.

Many retrofit technologies now being considered fall short of attaining NSPS, and the specter of a retrofitted plant having to meet ever more stringent environmental control standards will inhibit the development of many of these retrofit technologies. That possibility may have convinced some not to propose spending private funds on technologies which, while achieving substantial emission reductions and extending plant life reliability, may be immediately obsolete by changes in environmental regulations.

IMPACT OF ACID RAIN CONTROL LEGISLATION UPON CLEAN COAL:

If environmental regulations like those governing the reconstruction of an existing facility, as defined at 40 CFR 60.15, tend to frustrate promising retrofit technologies, passage of acid rain control legislation which mandates major, near-term reductions in SO2 and NOx emissions, would certainly stifle all clean coal technology development. The capital requirements of compliance with proposed acid rain control legislation would be immense and, inevitably, any funds available for new technological development would be siphoned off to ensure compliance with the regulatory program. Many existing plants might have to be closed on the basis of economic considerations, thus bringing the reliability of today's electric energy supply into question and raising a serious concern over the electric industry's ability to construct new facilities for tomorrow's needs. In reality, any immediate reductions would require widespread use of expensive and troublesome flue gas scrubbing systems because other more cost effective clean coal technologies are not yet commercially available.

Those who counsel that clean coal technologies will be commercially available for utilization before major emission reductions are required under current acid rain control proposals are wrong. The demonstration of new technologies simply takes time and, even if demonstration programs are successfully accelerated to the early 1990's, the utility industry will be unable to commit, plan and incorporate these technologies into their systems before the turn of the century. It takes approximately three years to design and build a commercial demonstration and two years to conduct testing. To be available for widespread use in the late 1990's, clean coal technology demonstrations must be initiated now. The clean coal technology demonstration program was designed to accomplish this end.

Mandatory emission reductions in the early 1990's, as called for by legislation currently under consideration in other Congressional committees, will force coal users to comply by using currently-available options. Clean coal technologies will not be available for widespread commercial deployment in the early 1990's time frame. Proponents of acid rain control legislation contend, however, that some emerging technologies may be sufficiently demonstrated in the early 1990's. They conclude that such technologies then could be used to comply with requirements for additional reductions which would be mandated by the mid-1990's. In the process of making expenditures to comply with a control program the utility industry will use limited funds to meet any mandated emission reductions. There may be little or no funds available to also develop new technologies during the early or late 1990's. At best, mandatory reductions will severely limit the number of new clean coal technologies that will be developed.

Finally, if a utility were to use a new technology without a vendor guarantee or if a utility were to risk incorporating the technology into a system before commercial readiness is proven and a failure were to occur, that utility might well be judged imprudent by the governing regulatory body.

The risks of such a venture are too great and the rewards too small. Incorporation of a new technology before it is proven is simply not a proper course to pursue.

CONCLUSIONS AND RECOMMENDATIONS:

Emerging clean coal technologies are clearly in the best interest of the United States. To the extent that mandatory reductions in emissions will adversely impact clean coal technology development and deployment, then the Coalition believes that this Committee's inquiry is of the upmost importance.

Given the lack of scientific certainty regarding the causes of aquatic and other natural resource damage resulting from acidic precipitation, it would seem that limited dollars could be more productively spent on development and widespread use of clean coal technologies. From an energy, environment and economic perspective, clean coal technologies promise to be far superior as alternatives to current control technologies -- particularly in avoiding those adverse economic and employment impacts associated with proposed control legislation.

Finally, from the point of view of the national economy, the orderly development and deployment of clean coal technologies is far preferable to immediate retrofit using scrubber technology. Cost effective technologies for new source and retrofit applications can be deployed with minimum impact on consumers' bills. The alternative, a mandated regulatory program which will force the use of existing technology, will result in rate shock. When you impose such costs upon our battered mid-western industrial base you also invite serious economic dislocations. American manufacturers struggling to compete in the international marketplace do not need the added burden of sharp increases in their cost of electric energy.

We urge the Committee to consider the need to provide additional cost-sharing assistance to further demonstrate retrofit technologies to repower or modernize existing facilities and so to encourage the development of the full range of clean coal technologies. Given the significant uncertainties currently facing the utility industry, it is clear that many are examining the extension of existing plant lives as an alternative to new capacity. If other market or regulatory forces are compelling the continued use of older facilities, then it is important to develop those technologies which not only enable greater reliability of service from these existing facilities but also ensure decreased emissions. Another statement of interest solicitation, similar to that conducted in 1984, would determine if there is sufficient interest within the affected industries to consider providing incentives, including making available the $350 million already authorized in the Clean Coal Technology Reserve, for further demonstrating clean coal retrofit technologies for existing powerplants.

If the United States is to receive the maximum benefit from a successful demonstration program, then the Congress and the Administration should also immediately examine the extent, if any, to which regulations must be changed and other financial incentives enacted to ensure the deployment of technologies once demonstrations are completed.

One of the most significant impediments to widespread use of new technologies is the uncertainty in which we now operate. Anything accomplished today to eliminate regulatory or financial uncertainty will better ensure the widespread use of commercially-demonstrated technologies tomorrow. For example, with respect to current environmental regulations (40 CFR 60.15) which may require the imposition of NSPS on a refurbished plant, it may be advisable to specifically exclude the cost of pollution control equipment. Also, some consideration should be given to including a more flexible standard in that instance where the 50% requirement is exceeded.

We recommend that the Committee examine all available means by which to enhance the prospects for the marketplace to adopt these new technologies. On behalf of the Coalition we would be pleased to work with the Committee on this important matter.

Finally, despite the absence of scientific support, if acid rain legislation is to be given further consideration, please focus upon the timetable of any mandated reductions. The full range of emerging clean coal technologies cannot be developed and deployed within the timetables for mandatory reductions now under discussion.

We need support from the Federal government to share in the risks of development and we need time to perfect and then to deploy these new technologies. We can do it; but provide us with the required assistance.

The Clean Coal Technology Coalition believes that these emerging technologies are an appropriate response for meeting environmental and energy objectives, not for the sake of the electric utilities, coal suppliers and others of the Coalition I represent, but rather for the sake of the American consumer that we are both privileged to serve.

Sources:

Chart on page 4:	U.S. Electric Generating Capacity and Peak Demand, 1984-2000 Report of the Edison Electric Institute on Nuclear Power, page 21, February, 1985.
Chart on page 9:	Emerging Technologies for SO2/NOx Removal Potential Department of Energy, 1985

The CHAIRMAN. Thank you.
Mr. McCormick.

STATEMENT OF JOHN L. McCORMICK, ENVIRONMENTAL POLICY INSTITUTE

Mr. McCORMICK. Mr. Chairman, I am John McCormick of the Environmental Policy Institute. It is a pleasure to be here this morning.

EPI has been active in the legislative debate on transportation utilization of coal and most recently helped to win support of the $400 million Clean Coal Technology Reserve. We are here today to continue our efforts to shift the Nation's fossil energy research priorities to the most pressing and immediate needs of the coal and electric utility industry.

This is an important hearing because the Congress and the DOE must agree with the direction that the CCTR takes from the very beginning. The engineering, electric utility and coal companies must know the Federal Government is standing behind this expensive commitment of scarce public funds.

As proposals are received and reviewed by the Department, it must report to you 30 days before making a final selection. If its list of qualified applicants do not include technologies having the greatest potential for reducing air pollutional emissions, the authorizing Appropriations Committee should consider redirecting the program's implementation.

Mr. Chairman, from the day the first bill was introduced, the CCTR has needed friends. We believe we help to find them by linking future acid rain control with this important first step, the research of less expensive and more effective air pollution control technologies.

Those environmental legislative and downwind State votes have no reason to support the second phase if they do not like the initial phase. We believe everyone can be satisfied with the results of the clean coal technology program, and this committee can play an important role by monitoring its early stages.

Mr. Chairman, we have seen the list of 51 proposals submitted to the program. We were disheartened, in part, by the limited number of retrofit technologies that were submitted. However, Mr. Chairman, before the DOE can sign the final agreement, Congress has an opportunity to sign off, though not veto, the selections.

I think it is at that point, Mr. Chairman, that we really can view the worth of the Clean Coal Technology Reserve. It would be my hope that the committee would direct DOE if the Congress is not satisfied to work with perhaps the Energy Research Advisory Board and the utility industry, namely EPRI, and other companies that have proposals that were not submitted to the Clean Coal Technology Reserve and encourage a second set of selections to augment the first set so that we really can get off on the right foot, concentrating on emissions reduction retrofit technology demonstrations.

Mr. Chairman, I refer now to the Lewis-Davis Acid Rain Report. It is a strong recommendation for spending Federal and private sector money on pollution control technology. Mr. Lewis saw the report as a significant step forward for both the U.S. and Canada. Canadian Prime Minister Mulroney saw the report as a significant departure from early positions of the administration.

There are four important findings of the report. They are:

Major sources of U.S. sulfur emissions are coal-fired electric power plants, industrial boilers and processes and ore smelters.

Second, acid rain is a serious environmental problem, both in the United States and Canada.

Third, acid rain is a serious transboundary problem where air pollutants emitted by sources in both countries cross their mutual borders, thus causing a diplomatic as well as an environmental problem.

Mr. Chairman, I do not think any environmental group could have worded the Lewis-Davis acid rain report any better. It concludes, Mr. Chairman, by stating that the availability of cheaper, more effective control technologies would improve our ability to formulate a national response that is politically and economically acceptable.

Now, the report stressed that priority should be given to those technologies which reduce emissions at the cheapest cost per ton, demonstrate retrofit technologies applicable to the largest number of existing sources, and can be applied to facilities currently dependent on the use of high sulfur coal.

We see no statutory relationship between the Federal Clean Coal Technology Reserve and the recommendations of the Lewis-Davis report. In fact, the CCTR and the report need never be joined except in their shared concept of promoting the commercial demonstration of emission reduction technologies. That task can be accomplished with far less than $5 billion.

Now a word on barriers to the deployment of clean coal technology. The impediments to their deployment are both real and assumed. The utilization of innovative pollution control equipment can be hindered by State and Federal rate setting regulations or the absence of stringent stack gas emission limits that force the market to react.

The market entry barriers related to demand can be minimized or removed by Congress legislating more stringent SO_2 performance standards for existing sources in the Federal Clean Air Act and in particular, Mr. Chairman, on those boilers that have exceeded their normal operating life and are now candidates for boiler life extension.

The research, development and deployment can be aided also by the proper use of the commercial demonstration waivers provision of the Federal Clean Air Act. At 40 C.F.R., part 60, subpart (D)(a), this provision limits the regulatory risk to those companies willing to demonstrate an innovative technology which has not been commercially warranted. If the results of the demonstration indicate that the equipment will not achieve the SO_2 standard, the project sponsors have to know they will not be cited for a Clean Air Act violation if they make a good faith effort to correct the design deficiency.

In any event, Mr. Chairman, the use of new technologies will be enhanced and expedited by the willingness of the Government, utility managers and public to cooperate. Our organization is beginning to look at the commercial demonstration waiver provision of the Clean Air Act, and our hope is that we can come to a mutually acceptable agreement between the environmental organizations, EPA and the industry that is going to take the risks on demonstrating these innovative technologies.

The priorities of the Clean Coal Technology Reserve, production of liquid or gaseous fuels from coal is not one of the goals of the CCTR as we understood the priorities. Emission reduction related proposals are the best buy for the DOE and the taxpayer, and they must be given the highest priority.

The House and Senate Appropriations Committees have reported the fiscal year 1985 appropriation that contained no specific outlines identifying the types of coal-related research the committees wanted to promote. We worked with the Clean Coal Technology Coalition and the Northeast-Midwest Institute and with Congressman Doug Walgren. I believe the guidelines which came from those discussions and were included in the final fiscal year 1985 supplemental are a good direction for the Clean Coal Technology Reserve to follow. I think that is the benchmark for which we ought to be striving.

In summary, Mr. Chairman, it is not overly optimistic to believe the Northeast and the Midwest can resolve the rare pollution disputes with Acid Rain Control Program. That remedy can provide the midwest the opportunity to rehabilitate much of its aging physical plant and increase the overall operating efficiency of its boilers while reducing their pollution levels. This is the purpose of the Clean Coal Technology Reserve. Used properly, it is an insurance policy for the Midwest coal users and producers.

Thank you, Mr. Chairman.

[The prepared statement of Mr. McCormick follows:]

ENVIRONMENTAL POLICY INSTITUTE

CLEAN COAL TECHNOLOGY RESERVE HEARINGS BEFORE THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

JOHN L. McCORMICK

JUNE 10, 1986

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ABSTRACT

The Clean Coal Technology Reserve (CCTR) is not a surrogate for a national acid rain control program. That transboundary air pollution problem must be resolved by the U.S. and Canada working together to reduce the concentration of acid-forming pollutants that damage public health, materials and the environment. The Lewis-Davis Report of the Special Envoys on Acid Rain to both the President and Canada's Prime Minister Brian Mulroney is a strong justification for spending federal and private sector money on pollution control technology demonstration projects.

The gap of scientific uncertainty continues to close as scientists on both sides of the border reach agreement on the causes and effects of acidic precipitation. Soon, the day of reconing will fall upon U.S. electric utility and industrial coal-fired boiler operators. They will need cost-effective means of reducing air pollution emissions from power plants. A carefully managed CCTR could provide the technology options needed to comply with a stronger emission control law.

Congress should measure the success of the CCTR by the number of technologies it generates that lower the cost and increase the efficiency of pollution control equipment. That was the principle justification for environmental and downwind-State legislators supporting the Reserve in the House one week after it approved the Gramm-Rudman-Hollings Budget Act. They were the swing votes for the $400 million CCTR and they can only be persuaded to fund the remaining $350 million second phase if the money is used to commercially demonstrate acid rain control equipment and processes.

It is not overly optimistic to believe the Northeast and the Midwest can resolve their air pollution dispute with a WIN - WIN acid rain control program. That remedy can provide the Midwest the opportunity to rehabilitate much of its aging physical plant and increase the overall operating efficiencies of its boilers while reducing their pollution levels. That is the purpose of the Clean Coal Technology Reserve and, and if used properly, it is an insurance policy for Midwest coal users and producers.

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INTRODUCTION

Mr. Chairman, and Members of the Committee,

It is a pleasure to appear before you this morning to speak for the Environmental Policy Institute on an issue of immediate importance. The Institute has, for fourteen years, been involved in the Congressional debate on coal development policy. We coordinated the national effort to enact the federal coal surface mining reclamation law and revision of the federal coal leasing program in 1975. E.P.I. has been active in the legislative debate on transportation and utilization of coal and, most recently, helped to win approval of the $400 million Clean Coal Technology Reserve (CCTR). We are here today to continue our efforts to shift the nation's fossil energy reserach priorities to the most pressing and immediate needs of the coal and electric utility industries.

Throughout its history, the Institute has not opposed development of the nation's domestic coal resources. Instead, we have worked to propose and establish groundrules to govern the mining, transport and utilization of that important fuel supply. We view the implementation of the CCTR as an integral part of the larger issues of air pollution control and decreased dependence upon foreign sources for boiler fuels. And, we continue to advocate protection of the economy of the Midwest while working with environmentalists in the Northeast and Canada to protect sensitive ecosystems from the damages of long range transport of sulfur dioxide pollution.

Economic development and environmental protection are two vital and compatible goals; and technology innovation is the key to promoting each. There is no shortage of skill and ideas in America. The engineers working with DOE, EPA, the Electric Power Research Institute and throughout the coal and electric utility industries have developed many promising technologies that are ready for commercial demonstration. The public can provide an important financial boost to those efforts and accelerate their transfer into the market place.

The CCTR is not a surrogate for a national acid rain control program and we believe you share that opinion, Mr. Chairman. It is, instead, a prerequisite for a solution which allows both the Northeast and the Midwest to win. The measure of the CCTR's success must be a long list of inexpensive and efficient pollution control options available to boiler operators. If the Department of Energy manages the CCTR as the House and Senate Interior Appropriations Subcommittees intended and as the downwind-State and environmental legislators understood its purpose, the Midwest electric utility customers will be the beneficiaries.

A CRITICAL TIME IN THE CCTR'S DEVELOPMENT

This is an important hearing because the Congress and the DOE must agree with the direction the CCTR takes from the very beginning. The engineering, electric utility and coal companies must know the federal government is standing behind this expensive commitment of scarce public funds. As proposals are received and reviewed by the Department, it must report to you thirty days before making a final selection. If its list of qualified applications do not include technologies having the greatest potential for reducing air pollution emissions, it will be too late in the fiscal year to redirect the Program's implementation.

It is the burden of those who need this Program most to assure the swing votes - the downwind State and environmental legislators in Congress - they are getting what they voted for. If pollution emission reduction technologies, particularly those designed for retrofit on existing boilers, spring from the CCTR over the next four or five years, the prospects for appropriation of the remaining $350 million in 1990 will greatly improve.

From the day it was initially introduced, the CCTR has needed friends. We helped to find them by linking future acid rain control with this important first step; the research of less expensive and more effective air pollution control technologies. They have no reason to support a second phase if they did not like this initial phase. We believe everyone can be satisfied with the results of the CCTR and this Committee can play an important role by monitoring the early stages of its implementation.

The Department is already familiar with most, if not all, of the likely applicants since it recently completed an evaluation of the 175 proposals submitted pursuant to Section 320 of the FY85 Supplemental. We have studied the inventory of respondants and find a broad mix of technologies but some are clearly beyond the scope of the CCTR as we envision it. The production of liquid or gaseous fuels from coal is not one of its goals, as we understand the priorities of the coal and utility industries. The emissions reduction-related proposals are the best buy for the DOE and the taxpayer and they must be given the highest priority.

This Congress may not have enough time to report a Clean Air Act reauthorization law but there is a strong likelihood the next Congress will tackle the issue and reach a conclusion. From every indication we have seen, the U.S. is approaching a day of reckoning with the complex and expensive problem of transboundary air pollution. Slowly and steadily the thinking among Midwestern coal and electric utility industry representatives is shifting from a "what if" to a "what now" attitude.

Canada's scientists are convinced that sulfur dioxide (SO2) and nitrogen oxide (NOx) pollutants, from both sides of the border, are causing serious and possibly irreparable harm to its aquatic and forest ecosystems.

On August 5, 1980, Canada and the U.S. signed a Memorandum of Intent (MOI) on transboundary air pollution, the intent being to vigorously enforce existing air pollution laws and to work towards the development of a bilateral agreement on air quality.

The MOI established a Co-ordinating Committee to negotiate a collective agreement on transboundary air pollution. In February, 1982, Canada proposed to reduce SO2 emissions by 50 percent east of the Manitoba-Saskatchewan border, contingent upon parallel action in the Eastern U.S. There was no response from the U.S. Then, in June, 1982, the U.S. representatives rejected Canada's proposal, citing lack of scientific evidence as the reason. There have been no official negotiating meetings since then.

In February, 1983, the final reports of the Technical Work Groups were released. Among them, the report issued by the Impact Assessment Work Group had a Canadian and a U.S. version. The Canadian version recommended a maximum level of 18 pounds of wet sulfate depositon per acre per year to protect all but extremely sensitive aquatic ecosystems. Separate Canadian/U.S. peer reviews of the reports were conducted. In July, 1983, the Canadian Peer Review Report concluded that scientific evidence was sufficient to warrant a major program of air pollution abatement. Again, there was no response from the U.S.

The U.S. cannot continue to refuse to negotiate a solution with Canada; partiularly in light of the fact that the Province of Ontario announced on December 7, 1985 its commitment to a very expensive air pollution cleanup effort. Ontario Premier David Peterson's ambitious program requires the Provinces's four main producers of acid rain-causing SO2 to reduce their emissions from the 1980 level of nearly 2 million tons to a maximum of 665,000 tons by 1994. That is a reduction of 67 percent.

The emission control cost is estimated to range between $1.5 and $2 billion but the program will have negligible impact upon Canada's acid rain problem if the U.S. refuses to take similar action. On average, every ton of SO2 that falls onto Canadian territory comprises half a ton that originates in Canada and half a ton that originates in the U.S. Unlike the dangers of exposure to trace amounts of toxic air pollutants, acid rain damage is caused by continuous exposure to high concentration levels. When Canadian scientists determine that 18 pounds of wet sulfate depositon per acre per year is the highest "acceptable" level to protect sensitive areas, reducing concentrations down to 25 pounds is not an adequate remedy. Therefore, a unilateral reduction plan initiated by Canada will not offer sufficient protection.

In a January 22 address to the New York Board of Trade, the Honorable Tom McMillan, Canada's Minister of Environment, stated: "If Canada were to eliminate every particle of sulfur dioxide and oxides of nitrogen from Canadian sources, it would be able to do nothing more than cut acid rain overall by half. In some of the most affected areas, however, that cut would not be enough to stem the damage being done."

He also pointed out to the U.S. audience that Canadians see the acid rain issue as "a litmus test of whether Canadian-U.S. cooperation works both ways". The U.S. and Candada are the most active trading partners in the world. According to the Environment Minister, "...we buy more of your goods than any other nation on earth -- Japan included. In fact, Ontario alone, just one of our 10 provinces, buys more from the U.S. than does all of Japan"

THE LEWIS-DAVIS ACID RAIN REPORT

The Lewis-Davis Report of the Special Envoys on Acid Rain to both the President and Canada's Prime Minister Brian Mulroney is a strong justification for spending federal and private sector money on pollution control technology demonstration projects. And, it provided an entree for both leaders to being their second round of discussions on acid rain control at a much higher level than their initial talk a year ago. The New York Times captured the real value of the Report in its January 12 editorial. It concluded with the statement, "Mr. Lewis's report deftly allows his President to beat a graceful advance".

The Special Envoys admitted they did not attempt to resolve all of the major differences between the two countries' positions on acid rain. Instead, they cite their recommendations as pointing the way "to a resumption of fruitful bilateral dialogue and constructive action that will help us relieve the stress that this issue has created.".

Mr. Lewis sees the Report as a "significant step forward for both the U.S. and Canada'. The Environmental Policy Institute agrees with that sentiment while recognizing the difficulty Mr. Lewis faced in presenting a stronger view to the President. The reader must understand that one year ago the Administration attributed acid rain to natural causes such as trees and volcanoes. The Report dispelled those notions by stating clearly:

"The major sources of U.S. sulfur emissions are coal-fired electric powerplants, industrial boilers and processes, and ore smelters."

To Canadian officials, who have been making that charge for the past five years, that may appear to be an obvious statement. However, that was not the Canadian Prime Minister's reaction. He saw the Report as a significant departure from earlier positions of the U.S. Administration and an important step forward in the process to resolve the acid rain problem. His statement contained a pragmatic combination of science, technology and diplomacy. He did, however, reaffirm that, "...our goal has to be a bilatoral accord that deals once and for all with this issue."

Two important findings of the Report that have ended any White House hopes of continuing its indifferent attitude towards Canada's concern are:

* "Acid rain is a serious environmental problem both in the United States and Canada. Acidic emissions transported through the atmosphere undoubtedly are contributing to the acidification of sensitve areas of both countries. The potential for long-term socio-economic costs is high."

* "Acid rain is a serious transboundary problem. Air pollutants emitted by sources in both countries cross their mutual border, thus causing a diplomatic as well as an environmental problem."

Another significant conclusion of the Report, with which the Environmental Policy Institute also agrees, is:

* "...at the present time, there are only a limited number of potential avenues for achieving major reductions in acidic air emissions."

The Report recognizes that currently only three emission control techniques are proven and available for reducing SO2 emisions from coal-fired powerplants: coal washing, coal switching, and flue-gas desulfurization. Unfortunately, the Report overlooked energy conservation as a limited, though available, means of reducing air pollution by reducing the amount of coal burned.

It states further that coal washing cannot eliminate enough SO2 to achieve a major reduction: coal switching would cost high sulfur coal miners their jobs; and, fluegas scrubbing would raise utility rates sharply. It concludes by stating that, "The availability of cheaper, more efficient control technologies would improve our ability to formulate a national response that is politically and economically acceptable."

Mr. Chairman, that is a very important principle of the Report and one that E.P.I. embraces. Based upon that finding, the Report recommends a very expensive $5 billion contol technology demonstration program. In this five year program, the U.S. government would cost-share the funding projects that have the potential for the largest emission reductions, measured as a percentage of SO2 and NOx removal.

Among the criteria it set down, were some of the essential requirements our organization urged the Congress to include in the CCTR. Given the difficultly the Reserve had in winning Congressional approval and the important role acid rain control legislators played in funding it, the Lewis-Davis guidelines are most appropriate.

The Report stressed that priority should be given those technologies that:

* reduce emisiions at the cheapest cost per ton;

* demonstrate retrofit technologies applicable to the largest number of existing sources, especially those contributing to transboundary air pollution; and,

* can be applied to facilities currently dependent on the use of high sulfur coal.

This may be the real strength of the Lewis-Davis Report and we congratulate its authors for their pragmatic recommendations. The U.S. must develop inexpensive and effective options for the Midwest coal and electric utility industries facing certain new pollution limits in the next several years. However, we do not agree that the taxpayer should be asked to provide $2.5 billion as the federal share of the commercial demonstration program.

RELATIONSHIP OF THE CCRT TO THE LEWIS-DAVIS REPORT

There is no statutory relationship between the federal CCTR and the recommendations of the Lewis-Daivs Report, nor should there be. The CCTR is, however, the embodiment of the Report's recommendation to implement a control technology demonstration program. In fact, there was some discussion last summer, by Mr. Lewis, that the U.S. might be willing to spend about $1 billion on an air pollution cleanup effort at the same time the House was considering the federal/private $1 billion cost-shared CCTR.

That caused concern because the two ideas are mutually exclusive. The CCTR is not limited to research projects sited in any particular geographic region. Whereas, Mr. Lewis was obviously referring to cleanup of powerplant emissions affecting the quality of Canada's environment. The Department of Energy is the necessary manager of the CCTR; it is not the regulatory authority that will implement acid rain emission reductions. In fact, the CCTR and the Report need never be joined except in their shared concept of promoting the commercial demonstration of emission reduction technologies. And, that task can be accomplished for much less than $5 billion.

REGULATORY AND OTHER BARRIERS TO DEPLOYMENT OF CCT's

The impediments to the deployment of clean coal technologies are both real and assumed. The utilization of innovative pollution control equipment can be hindered by State and federal rate-setting regulations or the absense of stringent stack gas emission limits that force the market to react. The market entry barriers related to demand can be minimized or removed by the Congressional legislation of more stringent SO2 performance standards for existing sources in the federal Clean Air Act.

Their research and development can be aided by proper use of the Commercial Demonstration Waivers provision of the Clean Air Act (40 CFR, Part 60 Subpart (D)(a)). This provision limits the regulatory risks to those companies willing to demonstrate an innovative technology which has not been commercially warranted. If the results of the demonstration indicate the equipment will not achieve the SO2 or particulate standard, the project sponsors have to know they will not be cited for a Clean Air Act violation if they make a good faith effort to correct the design deficiency. In any event, however, the use of new technologies will be enhanced and expedited by the willingness of the government, utility managers and the public to cooperate.

There is no shortage of technologically sound innovations for advanced air pollution control in this nation. The IGCC Coolwater Project, sponsored by Southern California Edison Co. and E.P.R.I. is an engineering marvel and one the industry and federal government are rightly proud. It has outperformed the expectations of its designers and continues to operate at better than 95% SO2 removal efficiency regardless of the type of coal it burns.

The U.S. electric utility industry has also pioneered the flugas desulfurization process, coal-water slurries and fuel cell development. And, the industry is cost-sharing and collaborating with Western European engineers on pressurized fluidized-bed and other advanced coal use and emissions control processes. The irony is that we continue to sharpen the learning curve on air pollution control but the U.S. has yet to create a lucrative market place for their use.

It has been nearly a decade since the Congress reauthorized the federal Clean Air Act. The public debate on the issue of coal combustion problems such as acidic deposition, health impacts, visibility impairment and materials damage continues. Failure to resolve these issues on Capitol Hill has shifted citizen action, therefore, to the courts, E.P.A. rule-making procedures and State legislatures. What the electric utility industry and its regulators are experiencing now is a piecemeal approach to dealing with these real and damaging pollution problems.

West Germany, Japan, and Scandanavian countries have not made as many advances over the U.S. technologically as they have with regulations to mitigate their air pollution problems. They are, by necessity, utilizing the equipment we are developing. They must protect public health and the environment beyond present levels of control and that is the market-driving force prodding the use of innovative and more effective clean coal technologies. We believe the U.S. will have to follow this path as well, and soon.

The domestic electric utility industry cannot continue to operate under the cloud of uncertainty it now finds itself. Whether it is the pending "tall stacks" regulation, proposed sulfate standards, international and interstate transboundary air pollution litigation, changing demand projections or unilateral actions by State legislatures to limit SO2 and NOx emissions, we are creating a managerial nightmare for the industry. These problems will not go away so they must be faced squarely and resolved quickly.

Enactment of pending Congressional acid rain control measures is guaranteed to stimulate market demand for clean coal technologies but it is, by no means, the only legislative method. There are other air pollution problems unique to the electric utility industry which Congress must address.

BOILER LIFE EXTENSION AND THE CCTR

The electric utility industry is in a period in which very little new generating capacity is being built. While many utilities are completing their construction projects, others are cancelling units on order and virtually no new orders are being placed. Georgia Power Company recently announced it does not plan to put any new coal-burning power plants on line until 2007.

Thre are two major reasons for this slowdown in plant construction. The electric utility industry has sufficient generating capacity in place and under construction to provide reliable electric service into the early 1990's if demand continues to grow at the moderate 2 to 2.5 percent estimated annual increase. And, the industry faces strong economic disincentives for new construction. The utilities experiencing the most serious financial problems are, for the most part, those with troubled nuclear projects.

Retirement of existing capacity is likely to be rare even though, by the turn of the century, 115 gigawatts of existing capacity (excluding hydroelectric units) will be more than 40 years old. Despite the operation and maintenance problems aging units present, utilities are finding it more cost effective and less burdensome, from a regulatory standpoint, to refurbish them than to add new capacity.

The decision to upgrade and not replace old boilers may provide consumer savings but it cancels one of the most important goals of the 1970 and 1977 Clean Air Acts. They were amended by the New Source Performance Standard which requires between 70 and 90% removal of SO2 emissions from new boilers. As they replace older, unregulated units, the nation's air quality should continue to imporve. However, those goals are being overridden by decisions to extend the normal operating life of boilers an additional 10 to 30 years.

BOILER LIFE EXTENSION AND THE CLEAN AIR ACT

The Congressional Office of Technology Assessment estimated, in its 1984 report, Acid Rain And Transboundary Air Pollutants, that U.S. electric utility boilers emitted about 17.4 million tons of SO2 in 1980. That inventory of total emissions was ranked by amount of actual plant emissions in an earlier E.P.A. report, Estimates of Sulfur Dioxide Emissions From The Electric Utility Industry, wherein the 200 largest SO2-emitting plants were listed in descending order of pollution output. Using that inventory, the Environmental Policy Institute constructed an analysis of the startup date of individual boielrs and other pertinant data for the 142 largest SO2-emitting plants in the U.S.

Where the estimated national coal-fired electric generation capacity approximates 200,000 MW, the E.P.I. survey captured about 182,000 MW of capacity and 14 million tons of SO2 emissions. The analysis identified about 385 million tons of coal consumption from the industry total of 570 million tons in 1980. Thus, 80% of the SO2 emissions and 90% of the coal-fired capacity were represented in the survey.

Among the hundreds of boilers, the oldest went on line in 1926 and the most recent was commissioned in 1984. In terms of the New Source Performance Standard regulations, 79,181 MW (42% of the total) went on line prior to 1970 and 167,929 MW (92% of the total) were in operation prior to the 1977 Clean Air Act reauthorization.

The E.P.I. analysis of the age of coal-fired generating capacity in the 31 Eastern States provides useful data showing the amount of capacity which has already exceeded normal book life. It also indicates the amount of capacity nearing or exceeding the time when plant managers must seriously consider preparaing to extend the life of the equipment, repair, or replace it. Table 1 presents the age and installed capacity of coal-fired equipment, by State, as of September, 1985.

TABLE 1. AGE AND MW OF INSTALLED COAL-FIRED ELECTRIC GENERATION CAPACITY IN EASTERN STATES
(units in megawatts)

STATE	>40 YRS	30 to 39	20 to 29	<20 YRS	TOTAL
AL	869	550	--	--	1419
GA	367	312	2700	--	3379
FL	94	188	2863	--	3145
IL	1098	389	3826	--	5313
IN	2785	830	4657	2004	10276
KY	--	1408	2183	1513	5104
MI	--	267	406	770	1443
MS	--	1458	5545	670	7673
OH	3587	1155	5459	847	11048
PA	--	768	3838	692	5298
TN	1226	3490	2600	--	7316
WI	--	868	20	--	888
WV	--	814	4836	--	5650
TOTAL	10026	12497	36233	9196	67952

Source: Environmental Policy Institute, September, 1985.

BOILER LIFE EXTENSION -- FROM A 'TREND' TO A 'TRADITION'?

From the data provided in Table 1, the Environmental Policy Institute constructed an unpublished and preliminary analysis of the startup date of individual boilers among the 50 largest SO2-emitting power plants in the U.S. They were targeted for mandatory scrubber retrofit by H.R. 3400 - the acid rain control bill introduced by Representative Henry Waxman (D-CA) in the 98th Congress. Table 2 presents the age and installed capacity of those units as of September 1985.

TABLE 2. AGE AND MW OF 1985 INSTALLED COAL-FIRED ELECTRIC GENERATION CAPACITY IN EASTERN STATES
(units in megawatts)

STATE	>30 YRS	20 to 29 YEARS	10 to 19 YEARS	<10 YRS YEARS	TOTAL
AL	869	550	--	--	1419
GA	367	312	2700	--	3379
FL	94	188	2863	--	3145
IL	1098	389	3826	--	5313
IN	2785	830	2785	2004	8404
KY	--	1408	2183	1513	5104
MI	--	267	406	770	1443
MO	--	1458	5545	670	7673
OH	3587	1155	5459	847	11048
PA	--	768	5710	692	7170
TN	1226	3490	2600	--	7316
WI	--	868	20	--	888
WV	--	814	4836	--	5650
TOTAL	10026	12497	36233	9196	67952

Source: Environmental Policy Institute, September, 1985.

When the U.S. Congress enacted the 1977 federal Clean Air Act, it included amendments intended to promote continuous improvements in air quality. Among the most effective, the New Source Performance Standards (NSPS) imposed tougher sulfur dioxide (SO2) emission limits on boilers constructed after the 1977 regulations went into effect. When they approved that law, the legislators anticipated a routine replacement of old and less stringently regulated equipment with new, pollution control-equipped boilers.

That goal is being frustrated, however, by electric utility managers choosing to continue operating old generating equipment and forgoing new construction. In light of the flattened electricity demand curve in the Midwest, the high capital cost of new power-generating equipment, and regulatory uncertainties, boiler life extension is becoming the preferred option for electric utility companies. It also represents a reversal of the nation's air quality improvement strategy since those older boilers will contine to emit levels of SO2 above that which technology can remove.

The national debate on acid deposition, the pending E.P.A. NAAQS regulations, resolution of the Section 123 litigation and State efforts to reduce SO2 emission levels all pose risks for utilities planning boiler upgrading in the near future. Economic feasibility and justification for current and planned boiler life extension projects could change drastically if subsequent federal pollution reduction orders are imposed to reduce acidic deposition concentrations.

To protect electric utilities, their customers, stockholders and the environment, national guidelines for boiler life extension should be considered and implemented by the U.S. E.P.A., or be codified by Congress in the Clean Air Act. The Agency could take the first step by assessing whether the limit of spending up to 50% of the replacement costs on "reconstruction" of an existing boiler is an outdated regulation disproportion with the present costs of either new plant or boiler upgrading.

In the 1977 Clean Air Act, the term "modification" is used in the definition of a "new source" and is, therefore, subject to N.S.P.S. requirements. "Modification" is defined in the regulations as:

> "any physical change in, or change in the method of operation of, an existing facility which increases the amount of any pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted."

In the regulations, there is an important distinction between "modification" and "reconstruction"; the latter being defined as:

> "the replacement of components of an existing facility to such extent that:
>
> (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that

would be required to construct a comparable entirely new facility, and

(2) it is technologically and economically feasible to meet the applicable standards set forth in this part."

Note: It is important to point out that the "50% of the fixed capital costs" is simply a regulation and not a provision of law.

Given the disproportionate costs of boiler life extension and replacement, the 50% ceiling is meaningless and should be revised downward. It can be reduced to a more appropriate level merely by E.P.A.'s initiating a rule-making procedure.

For power plants which substantially retain their character as existing facilities, application of best adequately demonstrated control technology is considered appropriate when any physical or operational change is made which causes an increase in emissions to the atmosphere. This is consistent with the principles of the Act's Prevention of Significant Deterioration provision. Thus, the regulations contain criteria for "reconstruction" (capital costs) that are independent from the criteria for "modification" (emissions increase).

The "fixed capital cost" includes such things as the cost of engineering, purchase and installation of major process equipment, contractor's fees, instrumentation, auxilliary facilities, buildings and structures. Costs associated with the purchase and installation of air pollution control equipment (e.g., baghouses, electrostatic precipitators, scrubbers, etc.) are not considered in estimating the fixed capital cost of a comparable entirely new facility.

When the EPA Administrator is asked to make a determination whether proposed replacement of components constitutes "reconstruction" he must consider:

(a) whether the estimated life of the facility after the replacement is significantly less than the estimated life of a new facility;

(b) the extent to which the components being replaced cause or contribute to the emissions from the facility;

(c) any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

From this discussion of the distinctions between modification and reconstruction, there are obvious implications for Georgia Power Co. and all boiler operators considering life extension projects. Either the increased amount of emissions (measured in kg/hr) or capital expenditures exceeding 50% of replacement costs can trigger the imposition of the percentage reduction requirements in the NSPS regulation. If that is the regulatory affect of a utility's boiler life extension proposal, it is likely the project will not be completed. However, a utility can appeal to E.P.A. for a waiver of NSPS requirements by proving there are economic and technical limitations on complying with those standards.

CONSUMER SAVINGS -- ENVIRONMENTAL QUALITY

The decision to upgrade and not replace old electric utility boilers may provide consumer savings and, from that aspect, we support this trend within the industry.

According to Duke Power's, William Parker, Jr., "Assuming that costs for upgrading for extended service will range from normal maintenance to $100/kW, there is a tremendous economic incentive to continue the operation of existing plants as an alternative to new plant additions costing an average of $1100/kW or 20 times the option of life extension". These savings appear to be large enough to justify emission reduction requirements at the same time the capital is committed to boiler life extension.

Comparisons between replacement costs and boiler upgrading costs require extensive site specific analysis and economic evaluation of the options. If a generalization of the capital savings is not in order, it is worth considering the views of three electrical engineers addressing the 1984 American Power Conference, in Chicago, as they estimated their company's savings.

Robert Carelock, staff engineer of Potomac Electric Power Co. described the decision to refurbish the 400 MW Potomac River station and extend the service of this retirement candidate to the year 2012 at a cost of $160/kW. Cincinnati Gas and Electric's Barry Pulskamp explained his company's willingness to spend an average of about $200/kW vs. $1000-$2000/kW for new capacity. Leonard McRee, of Duke Power, considered life extension "very economical" when comparing the $2000-$3000 for new capacity with $200-$300 for extending life of capacity.

Technological advancements in boiler design have provided great economies of scale since the 1950's. With the current high costs of material, labor and capital, however, the economies of large boilers have declined; and, there has been little improvement in unit heat rates for fossil power plants over the past 20 to 30 years. These are both good reasons for choosing the life extension option over new construction but they cannot be used as a subterfuge to escape the NSPS requirements imposed on new capacity. Furthermore, clean air advocates should not expect boiler life extension projects to be compelled to install NSPS-capable retrofit equipment as a compliance requirement. Emissions reductions should be required -- and they can be achieved -- without mandating the use of pollution control equipment capable of 90-95% removal efficiency.. The economies of boiler life extension will be protected when emission reduction technology options are allowed.

Allowing the use of technologies not as effective as flugas desulfurization or comparable emission control equipment is not a retreat from the 1977 Clean Air Act's goal of continuous national power plant emission reductions. However, preserving the current non-regulation of boiler life extension is more than a retreat; it is a direct threat to that goal. In fact, Schwengels, et.al., reported, in the May 1986 Public Utilities Fortnightly, the conclusions of sensitivity analyses show the change in assumed retirement age of boilers from 45 to 60 years resulting in a total national SO2 emissions increase of 4-6 million tons by 2010. That is clearly unacceptable.

The U.S. acid rain issue aside, the electric utility industry trend towards boiler life extension must be addressed by the Congress in the reauthorization of the Clean Air Act.

We can debate the age at which a boiler becomes "old", but, I would like to point out that EPRI's 1984 Fossil Plant Life Extension Conference Summary included, in the discussion of the Conference background, the following: "Typically, a fossil fuel power plant is designed for a 30-year life".

Heiges and Stoll, in their paper, Power Plant And Turbine-Generator Upgrading Economics conclude: "Upgrading the 25-30 year-old plant can reverse the degradation trend and provide plant life extension. Thus, upgrading early can provide a higher return on investment."

If the electric utility industry continues to extend boiler life without simultaniously reducing SO2 emissions, the nation will never realize the continued downward trend of SO2 air shed loading accomplished by the normal retirement of older and dirtier boilers. And, this is the dilemma the environmentalists, rate payers and the industry share. Meanwhile, the U.S. Congress is debating legislation to mandate a 10 million ton SO2 reduction law affecting many of the same boilers that are cadidates for life extension.

The question raised by boiler life extension decisions is: how can we bring the two goals together -- the consumer savings of boiler life extension and protection of the environment. The goals and the means to achieve them are straightforeward: provide regulatory and financial incentives to improve the efficiency of boilers while reducing their SO2 emissions.

THE "EXISTING SOURCE" LOOPHOLE

The federal E.P.A. is currently assessing the trend in electric utility boiler life extension and the impact it will have on future national air quality. There appears to be a growing recognition that an open-ended "retirement date" for non-NSPS boilers will result in higher total utility SO2 emissions. To examine that concern, the Agency commissioned a study of the environmental and economic impacts of imposing limits on existing S.I.P.-regulated boilers after they reach a certain age.

The analysis, prepared by ICF, Inc., looked at two approaches; a 1.2 lb. SO2/MMBtu emission cap on boilers older than 30 years and a post-30 year boiler NSPS (percentage reduction, in addition to the 1.2 lb. limit) requirement. In both cases, utility SO2 emissions would be reduced in the year 2010 by 11.2 to 13.3 million tons, respectively, below the 22.33 million ton base case forecast of SO2 emissions in 2010.

Both the 30 year/NSPS and the 30 year/1.2 lb. SO2 cap result in steadily larger SO2 emission reduction totals over time as more coal-fired boilers reach 30 years and meet the lower emission limits. By 1995, SO2 emission reductions, from the 30% of non-NSPS boilers affected, would total 3.5 to 4.0 million tons and by 2010 all boilers would be limited either to a 1.2 lb. cap or to N.S.P.S. levels.

Acid rain is a "time related" environmental problem. From that perspective, waiting until 2010 to achieve an SO2 reduction total sufficient to protect sensitive ecosystems in the Northeast may not be an acceptable strategy. Referring to Tables 1 and 2 will provide a measure of the amount of generating capcity affected if a 30year compliance date went into effect today. While 10,0260 MW of capacity are already 30 years and older, those units do not emit as much SO2 as the larger and more recent Midwestern boilers. Many of those newer units are among the largest SO2-emitting stationary sources in the U.S. Table 3 provides data pertaining to emission levels from the top three SO2 source States as an illustration of the tradeoff a 30 year/1.2 lb. cap presents.

Table 2. 1980 TOTALS AND RATES OF UTILITY SO2 EMISSIONS, CAPACITY BY AGE IN 1985 FOR 3 MIDWEST STATES

STATE	SO2 TOTALS ,000's tons	AVE. SO2 lb./MMBtu	MW <20 YR	MW 20-29	% STATE MW <30 YR
OH	2,171.6	3.8	6306	1155	67 %
IN	1,539.6	4.2	4789	830	67 %
PA	1,466.1	2.5	6402	768	0 %
TOTAL	5,177.3		17497	2753	75 %

In fairness to the 30 year/1.2 lb. SO2 cap, it should be noted that the proposed House and Senate acid rain control bills provide at least 10 years to fully implement a mandated emission reduction program. An increment of present capacity will, therefore, shift into the post-30 year catagory during that implementation period. This paper is not an endorsement of the 30-year cap as a viable alternative to a mandatory SO2 emission reduction program designed to protect sensitive environments in the Northeast and Canada. The two reguatory approaches may have to be implemented simultaneously if the U.S. intends to mitigate the acid rain problem in time to save lakes and streams in critically sensitive areas.

A 30 year/1.2 lb. SO2 cap may be an even-handed means of addressing boiler life extension and reforming the elusive retirement age of powerplants. It can also close the Clean Air Act "loophole" which allows non-NSPS boilers to remain in operation indefinitely while escaping emission reduction requirements. That problem may continue to exist even when the Congress legislates an acid rain control program.

Representatives of the electric utility industry are critical of a 1.2 pound SO2 cap approach. They suggested, instead, examining a 1.2 pound cap on a company-wide basis. That would provide the opportuntiy to buy much cheaper emission reductions. However, a company-wide trading system may not provide adequate offsetting potential for those companies operating several large and old units with high emission rates. State-wide trading appears to offer more to the industry.

If that approach sounds similar to H.R. 4567, the House Energy and Commerce Subcommittee acid rain bill, it is not. The legislation does not establish an emissions cap for non-NSPS units. Thus, plants located close to the Canadian border could emit higher SO2 levels without exceeding the State-wide 1.2 pound annual average. An emission limit on all non-NSPS plants exceeding 30 or 35 years of service would correct that problem.

The nation's 12 largest SO2 sources emitted 2.7 million tons in 1980, and would not be affected by a 30 year cap until the year 2000 or later. At the top of this list is A.E.P.'s James Gavin Station which went on line in 1974 and contributes more than 300,000 tons of SO2 to the nation's airshed. The U.S. cannot wait until 2005 or 2010 to bring SO2 emissions down from those large units. Thus, an acid rain mitigation strategy will need more regulations than a 30 year/1.2 lb. cap to limit the damage as quickly as possible.

Those which cannot be retired, could be added to the list of pollution control retrofit candidates needed to achieve the State's emission reductions. When the units are taken off line during retrofit construction, the utility managers will have to use that opportunity to upgrade the boilers as well. This represents additional investment for the utilities and increases the cost-per-ton of SO2 removed from those older units.

Since the 95th Congress could not justify imposing tighter restrictions on existing boilers in 1975, it is unlikey this Congress would mandate pollution control equipment on those same plants elven years later without considering the economic impacts to customers. Thus, some form of federal subsidies must be provided the utility companies to cover some or all of their retrofit costs.

To subsidize their construction, we urge the Congress to provide a national cost-sharing program funded by a national fee imposed on all electric utility customers. This approach has raised stiff opposition from those companies that have paid hundreds of millions of dollars already to reduce their SO2 emissions.

They feel it would be ironic if Southern California Edison customers, paying for power from the Coolwater plant to pay the same type of acid rain control fee as a customer using power from one of the largest SO2 sources in the nation. If SO2 -- not kilowatt-hours -- is the target of the nation's rath, perhaps we should be giving serious thought to taxing SO2 emissions to generate funds for capital subsidies. Plants meeting NSPS standards would pay a smaller fee. That approach meets the complaints of clean-burning plant operators and puts the financial burden on those companies emitting the greater pollution load.

The nation's utilities emitted 34 billion pounds of SO2 in 1980 and today's total is probably in that range. If a 10 cent per pound fee were imposed, the fund would collect $3.4 billion per year. A 2.5 cent fee would generate $850 million. At that rate, a plant emitting 200,000 tons of SO2 would pay $10 million per year. The plant used in that example generated 7 trillon watt-hours of power in 1980. The SO2 fee would be equivalent to 1.4 mills per kilowatt-hour for that power plant.

As this type of acid rain control program goes its course, power plant boilers will steadily be approaching the age where life extension or retirement decisions will be made. Those units fit for continued use can pay into the fund to buy emission reduction trades from the plants being scrubber retorfitted under the acid rain control program. Their purchase will augment the federal cost-sharing fund by an amount equal to the cost of SO2 removal which they bought into. If the fund receives those additional dollars, it can spread the subsidies more broadly and more generously - even to offset some of the operation and maintenance costs of the control equipment.. The goal would be a reduction of 8 or 10 million tons of SO2 as quickly and with the least economic impact on rate paers as is possible.

This approach should encourage operators of older and smaller boilers to take advantage of the cheaper emission eduction trades available while they forego the capital and O&M costs of retrofitting their own equipment.

The Congress cannot allow the electric utility industry to maintain boilers far beyond their book life without requiring some amount of emissions reductions. When the boilers reach that age, they are the least likely candidates for expensive emission reductions. Therefore, they should have the opportunity to purchase offsets within their states and for the lowest price they can find. A national acid rain control program operating simultaneously will create about 10 million tons of potential emission reduction trades from which to choose. When the cheapest deals are bought up for life extension boilers, the more expensive trades remain. That should prompt companies to shop early for the best bargains.

However the Congress addresses both acid rain and boiler life extension one fact must remain: America's heavily industrialized Midwest must survive any pollution control progam designed to assure protection of sensitive ecosystems in thje U.S. and Canada. This is the WIN-WIN acid rain solution the nation must strive for.

PRIORITES OF THE CLEAN COAL TECHNOLOGY RESERVE

When the House and Senate Interior Appropriations Committees reported the DOE FY85 Appropriation, they included $750 million funding for the CCTR. The two bills, however, contained no specific guidelines identifying the types of coal-related research the Committees wanted to promote. In fact, the research emphasis centered on using more coal rather than demonstrating methods to use coal more cleanly. Considering the environmental damage the U.S. and Canada are already experiencing with present coal use, the Environmental Policy Institute urged the Congress to reconsider the direction the CCTR was heading. The Institute testified before this Subcommittee, Senate Energy and Natural Resources, and the House Science and Technology Committees with the message that a clean coal demonstration program had to be just that if its sponsors expected any support from legislators representing States impacted by acid rain.

Working with the Clean Coal Technology Coalition, and the Northeast-Midwest Institute, E.P.I. drafted a list of guidelines which Congressman Doug Walgren included in a bill he introduced. That represented a turning point in the debate and improved the CCTR's chances of funding considerably. Most of those guidelines were later incorporated in the Senate Interior Appropriations Subcommittee's Report on the FY85 Supplemental.

Several of those directives are similar to the recommendat.ons of the Lewis-Davis Report. They included among other requirements that the technology:

- demonstrate, on a commerical scale, emission reduction equipment for existing boilers or improvement of new source performance standard equipment;
- will not duplicate equipment currently in use;
- should be available for commercial application no later than the 1990's;
- must result in emission levels that comply with or exceed Clean Air Act requirements in a cost-effective manner;
- must include a means for disposal of waste by-products in an environmentally acceptable manner.

These guidelines were the justification for such vocal acid rain control advocates as Congressmen Waxman, Sikorski, Walgren and Markey to urge their colleagues to support the CCTR prior to consideration of the FY86 Interior Appropriation bill. They were not the only acid rain control legislators supporting the CCTR. We believe, however, their strong opposition to the program would have doomed its funding when the House considered the Interior Appropriation just days after enacting the Gramm-Rudman-Hollings Budget Act.

ENVIRONMENTAL AND ECONOMIC BENEFITS OF THE CCTR

The benefits of the CCTR will be measured by successful demonstrations of inexpensive and effective air pollution emission comtrol technologies it funds. However, the ultimate economic and environmental benefits of the program will never be realized until the State Implementation Plans of the federal Clean Air Act are amended to reduce allowable SO2 and NOx emission levels on existing non-NSPS boilers. Only then will the new pollution control equipment actually be utilized and the effects of acid rain mitigated.

The electric utility industry is not placing orders for new generating capacity because demand has leveled off, diminished or remains uncertain for many companies. Their continued reliance upon old and weakly regulated coal-fired equipment beyond their normal book life means the U.S. will not realize the steady downturn in SO2 emissions anticipated in the 1970's. Extending the life of generating equipment instead of building new capacity may represent consumer savings but that policy is the antithesis of resolving the acid rain problem.

The CCTR funding, however, can be applied entirely to the commercial demonstration of pollution control equipment designed for retrofit on aging boilers being upgraded to avoid replacement costs. The remainder of this testimony will focus upon the types of pollution control technologies ready for commercial-scale testing on existing power generation stations which are approaching, or have exceeded, normal retirement age. When considered in that context, the CCTR is a unique opportunity for the electric utility industry to accomplish two important objectives. It can test methods and technologies to increase the overall efficiency of aging equipment and control acid rain-forming pollutants simultaneously.

CLEAN COAL TECHNOLOGIES AND ENVIRONMENTAL GOALS

One of the strengths of the EPRI list is its emphasis upon retrofit technologies. Many of those proposals are ideally suited to the boilers utility managers intend to keep on line longer than their normal book life. If these technologies are chosen by DOE to share in the CCTR, the Program will definitely be focussed in the right direction.

Not all of the projects can provide SO2 emission controls which exceed current NSPS requirements but many address multi-pollutant control at costs comparatively lower than flugas desulfurization. Those technologies will make it easier and less expensive for the electricy utility industry to comply when the reauthorized clean air law mandates huge SO2 and NOx emission reductions for non-NSPS boilers. Examples of pollution control efficiencies of these technologies are provided in Table 4.

TABLE 4. SUMMARY OF TECHNOLOGIES FOR POLLUTION CONTROL

DESCRIPTION	REMOVAL EFFECTIVENESS	AVAILABILITY
PHYSICAL COAL CLEANING	10-30% SO2	current
CHEMICAL COAL CLEANING	up to 90% SO2 25% energy penalty	post-1990
FLUGAS DESULFURIZATION	60-95% SO2	current
LOW EXCESS AIR/STAGED COMBUSTION	20-35% NOx	current
FIRST GEN. BURNER TECH.	40-50% NOx	current
2ND GEN. BURNER TECH.	50-70% NOx	1998
REBURNING TECHNOLOGY	50-80% NOx	post-1990
FLUGAS DENITRIFICATION	90% NOx	1990
ELECTROSTAT PRECIPITATOR	99.5% particulates	current
FABRIC FILTER	99.5% particulates	current
2 STAGE ELEC STAT PRECIP	99.5% particulates	1990
ELECSTAT ENHANCEMENT OF FABRIC FILTER	99.5% particulates	1990

LIMESTONE INJECTION/ MULTISTAGE BOILER--LIMB	retrofit 50-60% NOx & SO2 new- 70% NOx & SO2	1989
FLUIDIZED-BED COMBUSTION	90% SO2 - NOx ?	post-1990
E-SOX	50-80% SO2 99% particulates	1990

Source: Testimony of Frank T. Princiotta, Dir., Air and Energy Engineering Research Lab at R.T.P. North Carolina, U.S.E.P.A., before the House Subcommittee on Synthetic and Fossil Fuels, February 27 and March 28, 1985.

CONCLUSION

The Department of Energy is to be commended for its diligent implementation of the Clean Coal Technology Reserve. It has adhered to the rigid timetables in the law and has given every indication that the Administration supports this worthy program despite the nation's desire to trim federal spending and balance the budget. The DOE's earlier decision to convert the grant program to one that issues loans was partially corrected but may have had some dampening effect upon the enthusiasm prospective applicants had when the legislation was being considered. On balance, however, the Department is carrying out its responsibilities and appears to be on track.

The success of the CCTR can only be determined when the retrofit demonstration equipment is constructed and operating as designed. It will be several years, therefore, before the Program can be judged on that basis. Meanwhile, it must be the responsibility of its strongest advocates in the Congress to watch the Program carefully and assure the swing votes in the House and Senate that it is living up to their expectations. As the first $400 million is allocated to the successful applicants, the Congress can determine how to appropriate the remaining $350 million authorized for that purpose.

The CCTR can provide invaluable assistance to the electrtic utility and coal industries if it is applied to funding the commercial demonstration of pollution control retrofit technologies. Whatever the Congress, State and federal regulatory authorities or State legislatures decide with regard to acid rain and the other pending regulatory issues, the technologies this Program promotes will benefit the utilities. It was designed to focus upon emission reduction retrofits for old boilers; the same generating capacity many electric utility managers are hoping will carry them through the rough and uncertain years ahead.

The Chairman. Thank you.

Mr. Mannella, I hope you will express to Mr. Yeager our concern about his accident and our hope and wishes for a speedy recovery.

STATEMENT OF KURT E. YEAGER, VICE PRESIDENT, COAL COMBUSTION SYSTEMS DIVISION, ELECTRIC POWER RESEARCH INSTITUTE, AS PRESENTED BY GENE MANNELLA, DIRECTOR, WASHINGTON OFFICE, ELECTRIC POWER RESEARCH INSTITUTE

Mr. **Manella**. I will do that, Mr. Chairman. I want to thank you for the opportunity to appear here today personally as a last-minute substitute for Mr. Yeager. He developed what I believe we would all agree is very comprehensive testimony, and he looked forward to being here this morning. It is unfortunate that he could not, but I will send your regards to him.

I would like to summarize Mr. Yeager's testimony. I make no claim to be as expert as he in clean coal technology, but I will answer any questions that I can. Failing that, we will provide more detailed answers for the record.

Mr. Chairman, as you are aware, EPRI was established by the electric utility industry in 1972 to conduct a broad research and development program for the entire electric utility industry and its ratepayers.

EPRI's R&D mission is to develop new and improved technologies for electric power production, delivery and use and to help accelerate their availability, assuring an adequate supply of economic, reliable and environmental acceptable electricity. EPRI is supported by voluntary contributions from investor-owned, government-owned and cooperatively owned electric utilities across the Nation.

As we have testified before, however, one-third of EPRI's plan budget over the next 5 years will be directed to clean coal science and technology. In addition to the $500 million already invested by EPRI on this effort.

This commitment is based on the premise that coal utilization and environmental protection are mutually compatible and that improved technology is the key to compatibility, coupled with the fact that coal will be the fuel of choice for new generation capacity for the foreseeable future.

In summarizing Mr. Yeager's testimony, I would like to touch on the points which he makes at the conclusion of his written text.

As you have heard from other witnesses, we do believe that the Nation stands at a threshold of fundamental change in its technological base for coal-powered generation. The pulverized coal technology is probably close to being fully developed and cannot compete technologically with all of the demands that are going to be made on it in the future. So we are in the process of a technological transition, and coping with this transition will require an intensive joint commitment over the next decade on the part of industry and Government.

We have been operating on the basis and in the development of our Clean Coal Technology Program that you can get the best results when emission and cost reduction are achieved concurrently and not fitted against each other. This provides us, we believe, with an opportunity for some creative technology and for the development of national policy which allows it to be incorporated.

In that regard, Mr. Chairman, we think you ought to be commended for calling this hearing today, which we regard as the beginning of a process of dialogue whereby industry and Government can address this problem and come up with some cooperative solutions. We believe the Federal Government has to concentrate on the development of incentives which can have a profound effect on the private sector's ability to develop and utilize clean coal technology.

In other words, technology cannot do the job alone. It is virtually impossible for any technology today to develop to the point where on its own merits it will be quickly and readily accepted into the mainstream of commercial usage.

In particular with regard to the electric utility industry, which is a regulated industry, the need for incentives in both legislative and regulatory we think is extremely important.

In working cooperatively with Federal organizations, we would like to point to the highly successful Cool Water Integrated Gasification Combined Cycle Plant in California and the three atmospheric fluidized bed demonstration projects which are being led by the utility industry and EPRI and cite them as effective models for the technology demonstration efforts necessary to accelerate clean coal technology.

We do believe that additional demonstration efforts are necessary, such as in the pressurized fluidized bed combustion area and an array of cost effective retrofittable emission control options.

It is our hope that the clean coal solicitation that is just being completed will cover several pressurized fluidized bed demonstration projects, but the retrofit options should be pushed selectively. As Mr. Yeager indicated in the text of his testimony, a second solicitation with this in mind and perhaps with some short form requirements to encourage more response should be very seriously considered.

We do have plenty of opportunities for technological development. They are listed in the testimony. They have been cited by the witnesses. I will not go over them again today, but what we are concerned about as technologists is that the proposed legislation that we have seen has a degree of inflexibility that we think will limit and perhaps delay the implementation of this new clean coal technology and when applied to the generating capacity of the United States may effectively rule out new technology for a generation of plant lifetimes.

In conclusion, Mr. Chairman, we think that there is a window of opportunity now and in the near future for cooperative and creative approaches to solving this problem. We recommend aggressive action by Government and industry. We encourage more of a dialog with Congress through this hearing, for example, and with DOE and the administration on ways to better formulate the program within the Clean Coal Technology Reserve so that we can get the maximum mileage out of it.

Finally, Mr. Chairman, I would just simply like to note that EPRI has supported the Clean Coal Technology Demonstration Program from the beginning. We and the electric utility industry, through EPRI, are prepared and continue to do its part to implement that program.

Thank you.

[The prepared statement of Mr. Yeager follows:]

STATEMENT OF

KURT E. YEAGER
VICE PRESIDENT, COAL COMBUSTION SYSTEMS DIVISION
ELECTRIC POWER RESEARCH INSTITUTE

BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

Tuesday, June 10, 1986

Introductory Statement

Mr. Chairman, Members of the Committee:

I appreciate this invitation to discuss the Clean Coal Technology Program and its implications for electricity supply and environmental improvement. These implications are especially significant for the electric utility industry and therefore are of great importance to the Electric Power Research Institute (EPRI).

EPRI was established by the electric utility industry in 1972 to conduct a broad research and development program for the entire electric utility industry and its ratepayers. EPRI's R&D mission is to develop new and improved technologies for electric power production, delivery and use, and to help accelerate their availability insuring an adequate supply of economic, reliable and environmentally acceptable electricity.

EPRI is supported by voluntary contributions from investor-owned, government-owned and cooperatively-owned electric utilities across the nation. Over one-third of EPRI's planned budget over the next five years will be directed to clean coal science and technology. This is an addition to the $500 million already invested by EPRI on this effort. This commitment is based on the premise that coal utilization and environmental protection are mutually compatible and that improved technology is the key to compatibility. Sound scientific data derived from independent, peer-reviewed research must be developed in a timely manner on topics of environmental concern. In addition, information is required to reliably apply the most cost-effective clean coal technologies meeting the diverse needs of the utility industry.

Current environmental control capabilities must be improved by reducing capital and operating costs and preserving overall plant productivity. The importance of this effort is underscored by the fact that a new, large, conventional coal-fired power plant will typically cost $1.5 billion, with over 30% of this cost being directed toward environmental control. This includes sulfur dioxide (SO_2) scrubbing, particulate control, solid waste disposal, water treatment and plant cooling. These controls in their current form also have a major impact on plant efficiency and reliability. Closely associated with this issue is the increasing difficulty in siting new utility and other energy facilities.

The emission control debate has been driven by conflicting perceptions about the effectiveness of clean air programs. During the past decade these programs achieved about a 20% reduction in SO_2 emissions while utility coal use increased 70%. In essence, the debate concerns which sources should be required to further control emissions, by what means, and at whose expense. In spite of the progress achieved, the political focus is shifting from new sources to the more difficult problem of existing facilities.

The growing understanding of the complex interaction among pollutants indicates instead that the nation should be concentrating on developing an effective, sustained strategy to continue the substantial progress made in all aspects of emissions control. Especially important is vigorous application of new, clean-coal utilization technologies that combine emission control with the combustion or conversion process. The utility industry has been the national leader in developing and applying clean coal technology, thus, strengthening the likelihood of using coal cleanly in every respect this century.

Recommendations in the recent "Joint Report of the Special U.S./Canadian Envoys on Acid Rain" (The Lewis/Davis Report) reflect this progress. First, environmental protection can best be achieved through use of innovative clean coal technology rather than ineffective, "band-aid," plant modifications that compromise both productivity and the environment. Second, accelerated commercial demonstration and implementation of these technologies by regulated utilities will require cost-sharing and other incentives not available today. Third, continued research is required in the ecological and atmospheric sciences to better understand cause and effect relationships.

This is a symbolic change in approach and one which provides an opportunity for a positive solution, building on the utility industry's sustained commitment to resolution of the environmental and economic productivity challenges facing the nation.

Since its inception, EPRI has worked with the Department of Energy (DOE and its predecessor agencies), the Environmental Protection Agency, and other Federal agencies with energy research and development responsibilities to achieve mutual technical objectives. In the spirit of that long-standing cooperation, EPRI and others recommended an accelerated national program to better understand the environmental issues constraining the use of coal and to demonstrate and promptly apply promising new clean coal technology. This effort would build on activities already well underway within the federal and private sectors. It recognizes that a major pacing issue in commercial applications of the new clean coal technologies developed over the past decade is the magnitude of the resources necessary to confidently demonstrate their performance and reliability. This requires an intensive, joint effort by industry and government. My remarks today will focus on three principal aspects of this national Clean Coal Technology program; viz.,

1. Importance to the electric utility industry and the nation.

2. Development status and cost implications.

3. Impediments to development and deployment.

The principle which guides clean coal technology development is that true and sustained environmental improvement can only be achieved when both emission and cost reduction are achieved concurrently - not pitted against each other. Recognizing this principle the utility industry stands at a threshold of fundamental change in its technological base for power generation. The present commercial coal-fired technology is nearing the end of its development potential and is hard-pressed to respond effectively to the rapidly changing requirements being placed on power plants. New power generation options which can meet increasingly stringent siting and environmental demands without sacrificing productivity, and can be rapidly constructed in modular fashion over a wide range of unit sizes are particularly in demand. The next 10 years will therefore be of paramount importance, both in assuring future electricity supply and in controlling cost. It is in the strategic interests of the utility industry, the environmentalist community, and government alike to assure the success of this national program.

These changing institutional constraints have effectively priced new conventional coal-fired generating capacity out of the market for most utilities. For example, it costs three times more today in constant dollars to install a kW of conventional coal-fired electric generating capacity than in 1967 (Figure 1). As a result, the industry's future commitments for new capacity are not keeping pace with even modest electricity demand growth. This situation could become critical by the mid-1990s unless prompt action is taken (Figure 2).

Only a fundamental improvement in power plant technology can effectively respond to the growing constraints on coal-fired power generation and restore economic progress in electricity production. Failure to meet this challenge will not only sacrifice environmental protection but can undermine national economic competitiveness leading to further erosion of industry and jobs.

An accelerated, two-pronged approach can achieve this transition. The first is to promptly transfer improved coal technology from development to application. The second is to extract the last measure of performance from the existing electricity generating base to span this transition period. An intensive commitment from the utility industry, its suppliers and Government is needed over the next decade if we are to assure electricity supply while controlling costs and protecting the environment. Such commitment will determine whether real electricity cost in the 1990s and beyond can be controlled or will continue its recent upward trend (Figure 3).

The urgency of this joint commitment is underscored by the rapidly approaching challenge to the nation's electricity supply capability. Based on recent experience, we can expect electricity demand to continue to pace economic growth. Satisfying even modest growth during the remainder of the century will require a balanced strategy involving additional improvements in conservation and end use management, and greater productivity from existing generation capacity (reliability, heat rate and life extension), plus new generation capacity.

Figure 4 compares the capacity addition requirements of the historic 7%/yr demand growth with the 2.2%/yr. demand growth currently being experienced and projected for the foreseeable future. The absolute amount of new capacity required in these future decades, even under the lower growth conditions, will mirror the 1960s and early 1970s. This reflects the much larger generating base to which these additions will be made; and underscores that the nation's present generating capacity margin is a temporary anomaly, resulting from the reduction in demand growth experienced during the 1970s in the face of energy price escalations. The reverse can also be true if we do not plan now for the realities of the 1990s, and beyond. A successful life extension program for existing capacity is also essential if these new capacity requirements are to be held near the levels indicated. New clean coal technology now under development could reduce the cost of this necessary capacity expansion by more than 50% relative to current experience.

The industry's present, temporary, capacity margin provides a valuable window of opportunity for technical transition at minimal risk. The new, clean coal technologies can now be introduced through incremental, small scale additions, repowering of existing units, "off-balance sheet" plants, and PURPA co-generation opportunities. The rate of capacity expansion (Figure 4) for the late-1990s and beyond cannot, however, be achieved without advancing the technology to much larger-scale additions. It is therefore essential that this present opportunity be used to gain the experience and confidence necessary to meet the inevitable capacity expansion challenge.

The strategic environmental advantages of the new clean coal technologies relative to conventional wet scrubbing are also substantial. Figure 5 compares the short duration and relatively limited SO_2 control capability of retrofit scrubber requirements with the much greater potential of these new technologies. For example, proposed acid rain control legislation -- that would retrofit flue gas scrubbers on up to 100,000 MW of existing, high sulfur coal-fired generating capacity -- could cost the nation as much as $12 billion per year over the remaining life of the affected plants. A more effective alternative would be to introduce new clean coal technologies that offer greater emission control efficiency and improved generation productivity.

If the $200 billion necessary to implement the scrubber retrofit strategy over the remaining life of the affected plants were instead invested on new plants using advanced clean coal technologies, it would provide about half of the new generating capacity the nation is likely to require during the next 30 years. Such an investment would provide superior environmental control, not only for sulfur oxides but also for nitrogen oxides and solid waste, while improving the productivity and cost of power generation.

EPRI has also recently completed a sensitivity analysis of electric utility emissions based on North American Electric Reliability Council (NERC) projections of annual energy demand and capacity. The results indicate (Figure 6) that under the current Clean Air Act, up to 76% of existing, pre-New Source Performance Standard (NSPS) coal-fired power plants could continue operation to a life of at least 60 years without forcing SO_2 emissions to rise above current levels. On a regional basis, this potential is even higher in the Midwest, Southeast and Northeast. Thus, emission growth should not act as a deterrent to the continued operation of existing coal-fired plants. Essentially, the only factor which might reduce this capability is a higher load growth rate other than the 2.3% currently forecast. This analysis is described further in Attachment A.

Unfortunately, current regulations tend to ignore this trend and may discourage valuable plant refurbishment by requiring New Source Performance Standard (NSPS) levels of control. This effectively eliminates most retrofittable new clean coal technologies from consideration.

A third dimension of the Clean Coal Technology program recognizes that foreign countries, where a more cooperative partnership between government and industry has been encouraged, are aggressively moving to assume leadership in the development and commercialization of improved coal utilization technology in anticipation of a rapidly evolving world-wide market. Loss of U.S. technological leadership in the face of this pressure could have a major impact on domestic suppliers and force the utility industry to depend on these foreign sources. Recognizing that this dependence could have far-reaching security and economic consequences, EPRI has stepped up its efforts to take domestic advantage of world-wide technical opportunities by developing international consortia of power equipment development and manufacturers under U.S. corporate leadership.

With the goal of developing the best technology possible for U.S. utilities, these consortia will work cooperatively to demonstrate improved materials, designs and procedures. Focusing on boiler, turbines, balance-of-plant components, and retrofit applications, the consortia will validate individual components and develop equipment specifications that can be used with confidence by utilities. This ability to tap the cutting edge of worldwide development complements our efforts in coal combustion and conversion, and will permit these new approaches to coal utilization to achieve their full potential while strengthening U.S. competitiveness.

Unfortunately, EPRI is able to fund less than half the scope of its program at a time when the needs are increasing dramatically. EPRI's budget is not expected to experience real growth for the next several years thus severely constraining plans to financially support further development and demonstration initiatives. The relatively constrained condition of U.S. investment in electric power related research and development is indicated in figure 7.

Technology Development Status and Cost Implications

For many years, conventional pulverized coal units have been the only available coal technology proven for generating large amounts of electricity. In today's circumstances, these conventional coal units, with their federally-mandated flue gas scrubbers, have major disadvantages. Because these units have historically been characterized by economies of scale, they are relatively large units requiring long construction periods and large capital investments. A typical new 1000 MW power plant will cost over $1.5 billion. Over 30% of this investment will be for environmental control; licensing and construction may take ten years or more.

The inefficiencies and costs of current flue gas desulfurization technology coupled with the uncertain possibility that existing plants may require retrofitting of emission controls leads to the need for additional, simplified emission control options. These range from improved physical coal cleaning to combustion modification, furnace sorbent injection, partial and dry scrubbing. No single one of these options will satisfy the widely varying conditions in the range of existing coal-fired utility and industrial power plants. As a group, however, they can reduce the cost and productivity limitations of emission control today.

Selection will depend on a number of variables including control requirements, cost and functional criteria such as plant design and space limitations. Functional criteria can be a particularly important constraint when considering retrofit to existing plants. Unlike new plants where the boiler and emission controls can be designed as an integrated unit, retrofit requires adaptation to a plant not designed for such modification. This can lead to compromise and additional expense.

EPRI has examined a variety of emission reduction requirements in terms of the potential savings achievable through optimal use of this array of new technologies. In each case, capital and annualized costs were reduced from 35% to 60%. Unfortunately, the legislative proposals developed thus far fail to provide the flexibility necessary to fully implement these opportunities, thus effectively limiting utilities to either scrubbing or retiring the majority of their units.

Figure 8 summarizes various options for improving the cost and efficiency of various emission control options for existing and new coal-fired power plants. These include commercially available physical coal cleaning and flue gas wet scrubbing (shaded) which reflect relative extremes in control efficiency and cost.

By comparison, a variety of other developmental capabilities (indicated by the dashed lines) provide the potential for both substantially improved efficiency and reduced cost. In each case, prompt commercial application depends on large scale, commercial demonstrations to validate performance, operability and reliability.

In summary, clean coal technology development has had two primary objectives; viz., to

1. Provide an array of retrofittable emission control options which satisfy at reduced cost, the void between present physical coal cleaning capabilities and flue gas scrubbing.
2. Provide improved coal utilization alternatives for both repowering or new plant applications, which combine high levels of emission and effluent control with reduced costs.

These options are described further in Attachment B. An important distinction should be recognized between these objectives and the technologies they represent. The latter has the potential to reduce the absolute cost and increase the productivity of power generation. The former objective can only limit the cost increase which would otherwise be imposed by more expensive retrofit controls.

Figure 8 indicates that the more effective objective is the use of new coal utilization technologies such as atmospheric fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC), and integrated gasification combined cycle (IGCC) which have the potential to be more effective both in terms of environmental control capability and cost. These technologies combine emission control within the combustion or conversion process, rather than adding new process complexity. The result is both greater emission control efficiency and improved generation productivity to fundamentally resolve perceived conflicts between energy and the environment. This underscores the value of economic and regulatory incentives that emphasize prompt transition to these improved coal utilization options rather than diverting resources into "band-aid" retrofit efforts.

The principal appeal of these technologies is that they currently address the major factors affecting coal-fired power generation - notably, emission control complexity and cost. Combining emission control with the combustion or conversion process is inherently less costly and more efficient than removing pollutants from the flue gas.

The most effective national clean coal utilization program therefore should have four major elements. Based on the existing development foundation, all four objectives can be achieved within the next five years if the necessary emphasis and resources are provided. The four objectives are:

- Establish a sounder scientific base to guide the nation on the needs and appropriate timing of emission control.
- Develop and demonstrate the array of potentially more effective retrofittable emission control alternatives to current flue gas scrubbing technology.
- Develop and demonstrate the advanced coal utilization technologies, e.g. atmospheric fluidized bed combustion, pressurized fluidized bed combustion, and gasification combined cycle, over a sufficient range of conditions to establish performance, cost, and reliability.
- Establish incentives to encourage the prompt commercial implementation of the demonstrated technologies.

Based on successful accomplishment of these four objectives, broad commercial implementation of successful clean coal technology can be initiated during the 1990's.

The highly successful Cool-Water IGCC and the three AFBC demonstration projects being led by the utility industry and EPRI provide effective models for the technology demonstration efforts necessary to accelerate clean coal technology. EPRI has been pleased to be a partner and catalyst for these projects and looks forward to continuing its cooperative efforts, where possible, to stimulate the prompt acceptance of improved technology.

EPRI therefore supported the DOE Clean Coal Technology program mandated by P.L. 99-190, for cost-shared demonstrations. This is one of the most essential ingredients today in accelerating the utilization of clean coal technology. We agreed with the intent of Congress that DOE's role be as a risk-sharing partner, not a loan office which would be of little value to the regulated utility industry who will lead many of these necessary demonstrations. Unfortunately, confusion caused by the DOE Program Opportunity Notice (PON) on this subject, coupled with its unrealistic information requirements, has discouraged a number of potentially important utility projects.

Specific comments on the PON for this program are included as Attachment C. We are also concerned that this new program may be financially more than offset in 1987 by the $229 million reduction in the DOE request for the Fossil Energy Research and Development program. This represents a 73% funding decrease in this important, complementary program.

The following summarizes EPRI's preliminary assessment of the April 1986 response to the PON relative to electric utility applications:

- The proposals submitted are less than one-third the number of clean coal demonstration projects identified to DOE a year ago. Many were apparently cancelled because of the discouraging requirements in the PON relative to the private sector's understanding of the original Congressional intent.

- The areas of least response, relative to the opportunities identified originally, appear to be the retrofittable emission control options, particularly lower cost engineered plant modifications. The following summarizes this preliminary observation by technology category. It is not intended to reflect in any way on the quality of specific proposals for which there appear to be very worthwhile examples in each category.

Retrofittable Emission Control Options

- coal cleaning - limited response
- combustion modification - limited response
- flue gas desulfurization - very limited response

Repowering and New Plant Options

- AFBC - strong response
- PFBC - strong response
- Coal Conversion - limited response
- Fuel Cells - strong response

o A simplified and unambiguous "short form" PON would encourage the retrofit emission control options which are notably absent in the response. These are especially important to reduce cost if further emission reductions become necessary for existing plants.

DOE also has a unique opportunity to work more closely with the private sector in resolving the various constraints, often resulting from governmental action, on the use of innovative technology. In this context, cofunding is only one way in which DOE can help. DOE should also lead, when opportunities arise, in programs which could result in increased private sector R&D efforts and reduce the need for direct DOE involvement. For example, the state of Ohio has recently taken the initiative of funding clean coal technology demonstration programs in that state in such a way that the industrial partners retain the commercial and managerial incentives. The state role is to promote demonstrations by sharing part of the cost and insuring acceptance of demonstrations in the utility rate base.

This underscores the need for a more effective coordination mechanism between federal and state governments to develop cost and risk incentives in as effective manner as possible, including assured cofunding for multi-year demonstration programs. The establishment of this coordination mechanism, for example, could be encouraged by a conference of governors from coal utilizing and coal producing states along with the heads of affected federal agencies. An industry task force also needs to be established that is empowered to provide combined business and technical judgment, guidance, and direction for the DOE Clean Coal Technology program. Such a panel could provide valuable input to the DOE and Congress in the prioritization and acceleration of clean coal technology having important commercial and environmental potential.

Impediments to Development and Deployment

Private Sector Constraints:

The electric utility industry, which is the ultimate user of most new clean coal technology, is a financially stressed, regulated industry whose profits do not necessarily reflect risk. Major risk is associated with the incorporation of innovative technology into an established and complex electric power system whose primary concern must be reliability and cost of service. Adequate incentives for the regulated utilities to bear these risks are not present today.

Similarly, hardware suppliers cannot be assured of a sufficient return on R&D investment to maintain technical leadership in the current limited domestic market situation. R&D is only the first step which, if successful, will require time and much greater expenditures for engineering, manufacturing, marketing and capital before a profit is realized. The possibility of changes in government policies over this period further amplifies the risk.

National Energy Policy:

National energy policy must consistently recognize the importance of clean coal technology, not only for environmental protection, but for national security and economic stability. Priorities for developing promising technology should be selected in conjunction with the private sector user of that technology. Government's foremost goal in such a policy should be to expedite the availability and use of these technology improvements. Implicit in such a policy is protection of development and demonstration programs from arbitrary changes in direction and funding level. Program stability is the key to successful development and implementation of new clean coal technology; and furthering the use of our nation's most abundant fossil energy resource.

An additional element of this policy should be elimination of the all too often adversarial relationship which has existed between government and the private sector in energy matters. This includes technology development, regulation, markets and risk sharing. This has been a fundamental impediment to progress relative to other countries where a more cooperative attitude has prevailed. It similarly restricts U.S. competitiveness in the increasingly international scope of the energy market.

Risk Sharing and Cost Recovery:

The most critical step in developing commercially viable clean coal technology is the demonstration of that technology. This must be performed on a sufficient scale and range of conditions to reduce the risk of application to a level acceptable by the commercial user while maintaining a competitive price. Government must share in this risk if the efforts are to bear fruit.

Government agencies and regulators must understand and accept that the cost of research, development and demonstration is a business expense that will ultimately benefit the ratepayer and consumer. Unfortunately, increasingly stringent prudency and rate suppression determinations effectively focus the risk and cost burden on the stockholder, thus discouraging the power industry from planning, developing, and implementing new generation capacity. This has a corresponding impact on equipment supplier investments for new technology development, demonstration and production.

This disincentive is occurring at a time when clean coal technology developments initiated during the 1970's are approaching commercial reality. A new regulatory formula is required that recognizes the nation's strategic need for low cost electric power to improve productivity, industrial competitiveness, and economic stability. This formula must protect the development and commercialization of technological improvements, which have historically formed the basis of our nation's success, from short-term political expediency.

Existing Emission Control Regulations:

The Clean Air Act as amended in August 1977 unfortunately signaled a shift away from quantitatively supported national health and welfare based ambient air quality criteria. Administrative definitions of the "best technological system for continuous emission reduction" is now the primary regulatory mechanism. This change, most evident in the Standards of Performance for New Sources (NSPS), can be ratcheted at administrative discretion and tends to discourage productivity and innovation. Conversely, it increases compliance cost by preferentially encouraging one control method relative to others.

This so called technology "forcing" concept is taken even further under the Clean Air Act. Best Available Control Technology (BACT) is required in areas which have already attained the national ambient air quality standards. here the required control technology is selected on a case-by-case basis by the states, but must be at least as strict as NSPS. As a practical matter, such random application of the technology "forcing" concept has proven instead to be technology inhibiting. Even though an unencumbered clean coal technology may demonstrate both economic and environmental advantage, the additional technical and cost penalties associated with locally determined BACT may delay or prevent its commercial application. This problem could be overcome by developing emission standards that define only control levels which are specifically linked to scientifically defined health and welfare requirements. Selection of the method of control for meeting those requirements should then be left to the user. Such change would encourage freedom of choice in the use of clean coal technologies.

Further, the demonstration of new and innovative technology to reduce emissions and improve productivity should be encouraged by recognizing the risks inherent in such demonstrations. Today, the potential advantages to the first users of new, clean coal technologies tend to be negated by penalties associated with failing to meet all regulatory criteria during their commercial demonstration period. This is compounded by the uncertainty that even if successful, the technology may be rendered obsolete by additional administrative regulatory judgments.

Finally, existing regulatory requirements may discourage the effective refurbishment of many existing plants by forcing them to meet NSPS. The resulting demand to use conventional wet scrubbing, rather than flexibly encouraging new clean coal retrofit technology where necessary, will typically more than double the cost of refurbishment.

Proposed Emission Control Regulations:

Although a variety of legislative initiatives are being proposed to achieve further emission reductions, their inflexibility and focus on existing plants serves to encourage the retrofit of conventional wet scrubbing rather than the deployment of innovative clean coal technology. Their impatience to achieve short-term results tends to dramatically increase cost and undermine the sustained environmental progress they propose to promote. This is especially true in those states which could benefit the most because of their dependence on local high sulfur coal for power generation. This stringency in control level and compliance schedule would essentially eliminate the use of more cost effective retrofittable clean coal technologies such as improved coal cleaning, furnace modifications and dry, partial or in-duct scrubbing in those regions.

In terms of impact on coal utilization, only very low sulfur eastern compliance coal would increase substantially. This would occur at the expense of midwestern and moderate sulfur level eastern coal. Western low sulfur coal utilization would not be appreciably increased. On the other hand, innovative clean coal technology encourages freedom of choice including a wider range of coal quality. As a result, this potential dislocation in coal production could be avoided.

The unnecessary cost impact of proposed legislation on the large population (over 150,000MW) of unscrubbed, coal-fired plants would also tend to encourage forced retirement of valuable power generation facilities. This would occur at a time when the present disincentives to new generation capacity are likely to severely strain the nation's electrical supply capability. The resulting escalation in power cost would further erode productivity and competitiveness. For example, an emission control strategy which effectively depends on retrofitting conventional wet scrubbing to existing plants is expected to cost about $250/KW. Flexibility to use new clean coal technology to best advantage could reduce this cost by 60%. The relative cost effectiveness, in terms of cost per ton of SO_2 or NO_x controlled, is equally striking.

Finally, as discussed earlier, such short-sighted diversion of capital into expensive, "band-aid" retrofit control strategies will delay new clean coal power plants using improvements such as fluidized bed combustion and coal conversion which combine emission control with reduced cost. The result will be eroding environmental quality and economic productivity--quite contrary to the expectations of the legislation.

Summary

1. The nation stands at a threshold of fundamental change in its technological base for coal-fired power generation. The present commercial technology is nearing the end of its development potential and is increasingly hard pressed to respond to the rapidly changing requirements being placed on the industry. An accelerated, two-pronged approach is necessary: first, promptly transfer improved coal technology from development to application and second, extract the last measure of performance from the existing generation base necessary to span this transition period. Coping with this urgent transition will require an intensive, joint commitment over the next decade on the part of industry and government.

2. The principle which guides clean coal technology development is that true and sustained environmental protection can only be achieved when emission and cost reduction are achieved concurrently--not pitted against each other. This principle can best be realized through the accelerated use of innovative clean coal technology in new plants rather than expensive, ineffective, "band-aid" plant modifications which compromise both productivity and the environment.

3. The actions of the Federal government in direct support of energy related research, development and demonstration, and

in the form of incentives, have a profound effect on the private sector's ability to develop and utilize clean coal technology. Federal programs need to consider the underlying circumstances affecting private industry and the importance of electric energy and coal to the nation's economy and security needs. The rate of commercialization and use of improved technology also depends on legislative and regulatory incentives. Too often our dependence on the adversarial approach makes the uncertainties and conflicts restricting coal use more severe and disruptive than necessary and restricts the introduction of technological improvements.

4. The highly successful Cool Water integrated gasification combined cycle and three atmospheric fluidized bed demonstration projects being led by the utility industry and EPRI provide effective models for the technology demonstration efforts necessary to accelerate clean coal technology. Additional demonstration efforts for these and other repowering and new plant options, such as pressurized fluidized bed combustion, plus the array of cost effective, retrofittable emission control options should be initiated through joint industry/government sponsorship. Unfortunately, the issues surrounding the recent DOE Program Opportunity Notice have served to cloud Congressional and Administration intent on this matter.

5. There is no shortage of opportunities to improve the efficiency, reliability and environmental performance of coal utilization. We are learning how to produce power cleanly from coal in a variety of forms meeting the demands of the diverse national energy system. The question is whether we can reduce this knowledge to practice in a period when both regulatory uncertainty and financial disincentives constrain the effort.

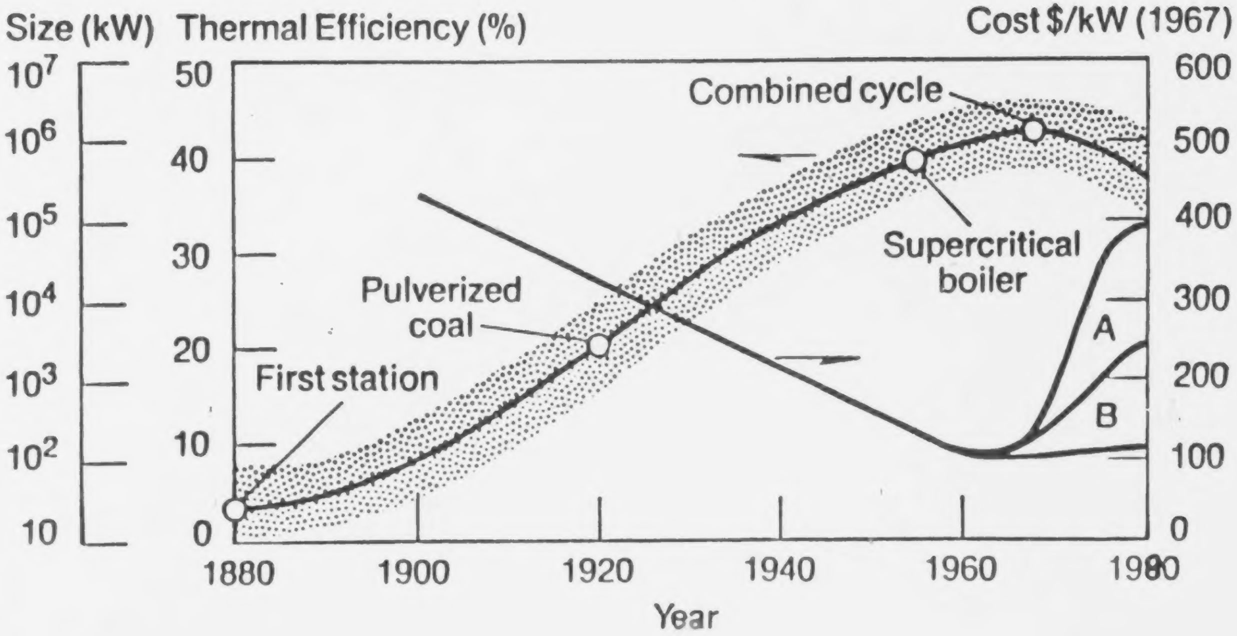
6. The inflexibility of proposed legislation intended to further reduce emissions tends to discourage the application of innovative clean coal technology and limit freedom of choice. The result may be to substantially increase the cost of compliance and delay implementation of new clean coal generating capacity which combines emission control and cost reduction. The result will be eroding environmental quality and economic productivity--quite contrary to the expectations of the legislation.

7. The future is now, and success depends on prompt, aggressive action by government and industry. The problem affects all phases of the development and commercialization cycle, but is greatest in the financially-intensive demonstration steps

necessary for commercial confidence. The Clean Coal Technology Demonstration program supporting private sector demonstration initiatives can substantially enhance the nation's ability to commercialize the many developments in clean coal technology. EPRI is prepared to continue to do its part in implementing these efforts.

Figure 1

POWER PLANT EVOLUTION



A = Environmental control cost

B = Impact of delays and losses in construction productivity

Figure 2

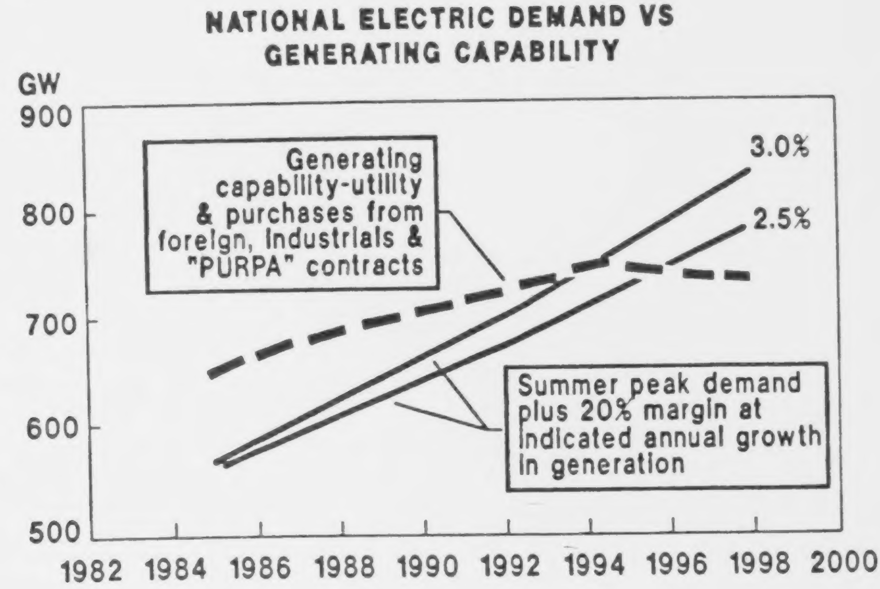

NATIONAL ELECTRIC DEMAND VS GENERATING CAPABILITY
GW
900
800
700
600
500
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
Generating capability-utility & purchases from foreign, industrials & "PURPA" contracts
3.0%
2.5%
Summer peak demand plus 20% margin at indicated annual growth in generation

Figure 3

U.S. ELECTRICITY PRICES
1929-2010

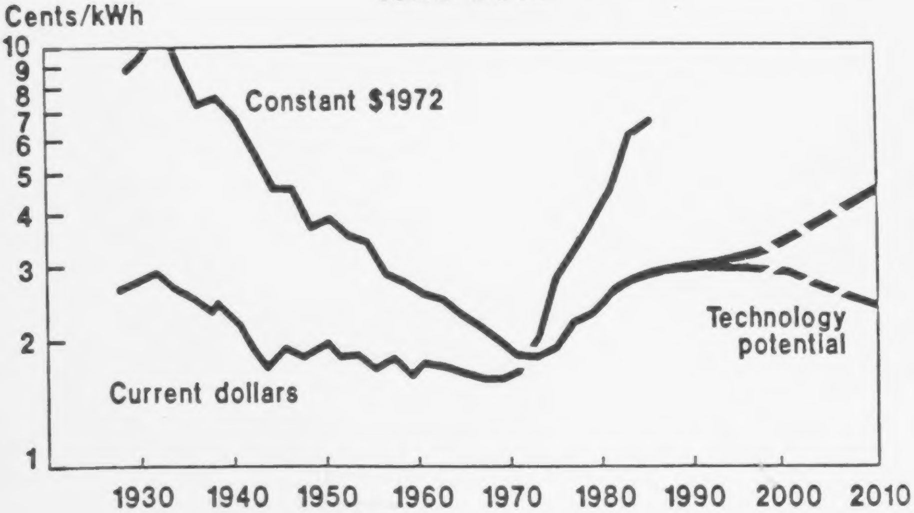


Figure 4

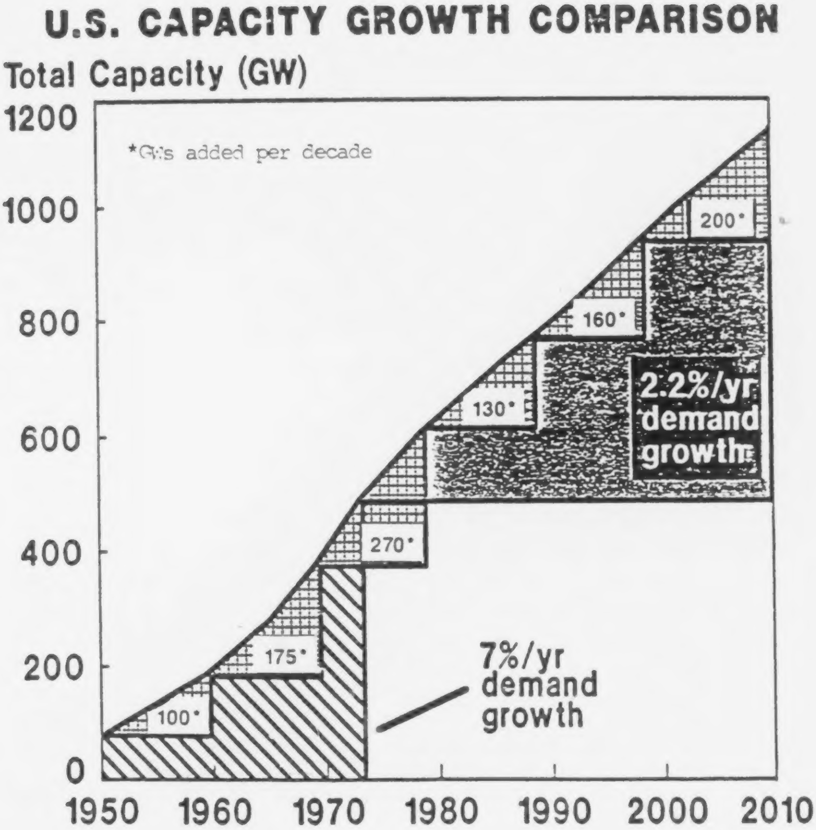
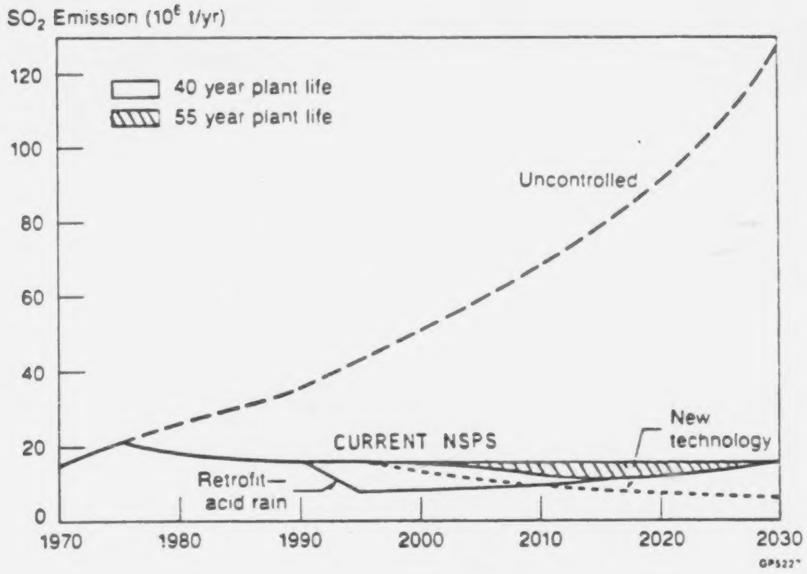

U.S. CAPACITY GROWTH COMPARISON
Total Capacity (GW)
1200
1000
800
600
400
200
0
1950
1960
1970
1980
1990
2000
2010
*GWs added per decade
100*
175*
270*
130*
160*
200*
7%/yr demand growth
2.2%/yr demand growth

Figure 5

ANNUAL UTILITY SO_2 EMISSIONS



NEW TECHNOLOGY SUCH AS FBC AND GCC PROVIDE MUCH MORE EFFECTIVE APPROACH TO EMISSIONS REDUCTION THAN "BAND-AID" RETROFITTING OF OLD PLANTS, WHILE ALSO IMPROVING PRODUCTIVITY.

Figure 6

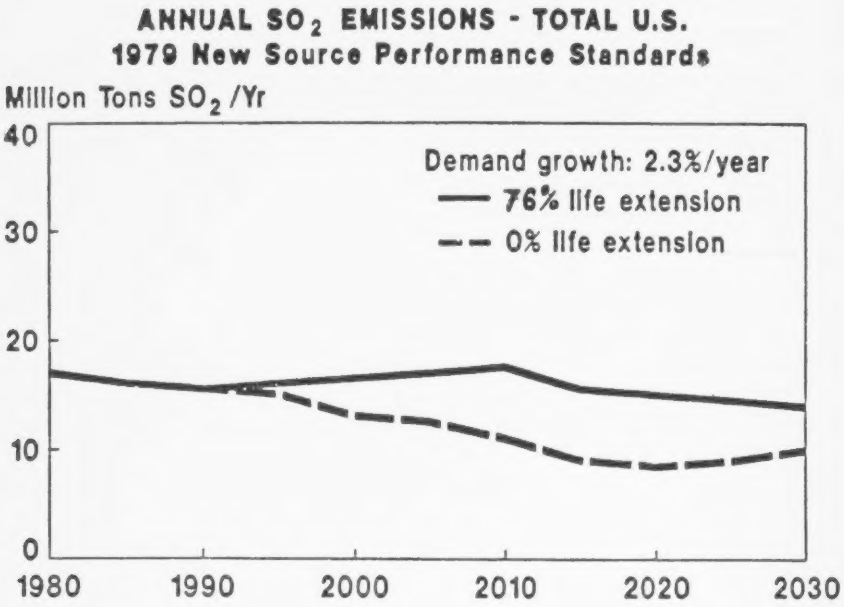

ANNUAL SO_2 EMISSIONS - TOTAL U.S.
1979 New Source Performance Standards
Million Tons SO_2 /Yr
40
30
20
10
0
1980
1990
2000
2010
2020
2030
Demand growth: 2.3%/year
76% life extension
0% life extension

Figure 7

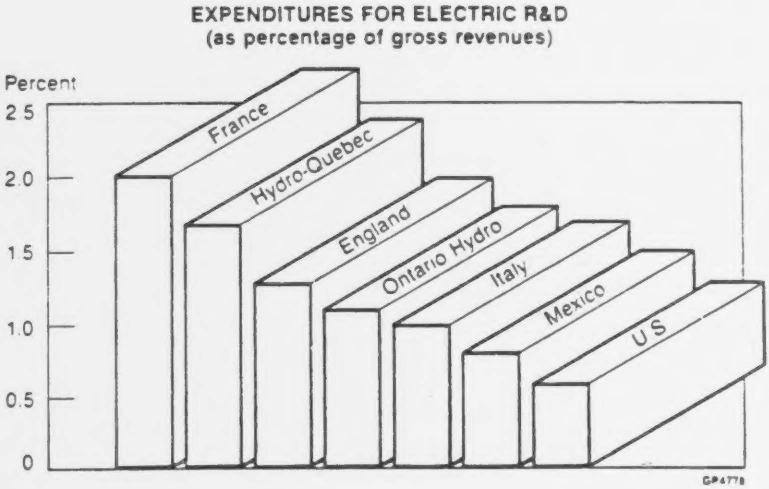
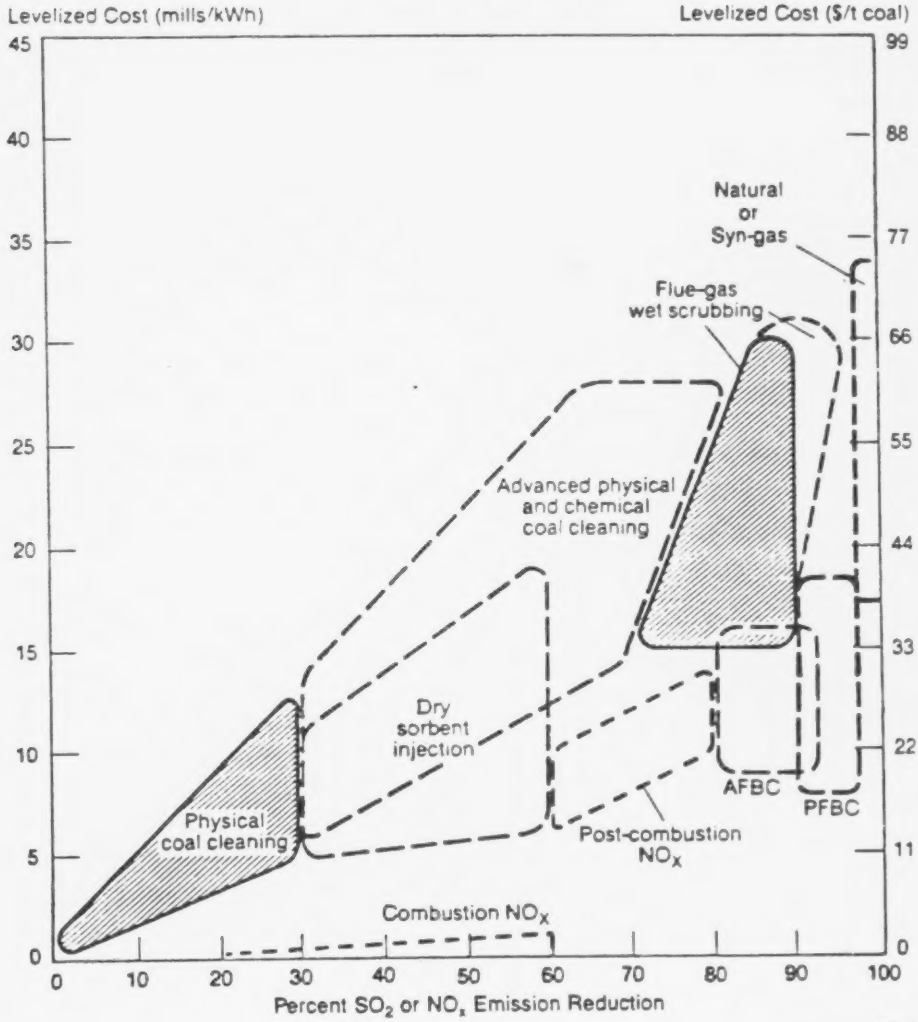

EXPENDITURES FOR ELECTRIC R&D
(as percentage of gross revenues)
Percent
2.5
2.0
1.5
1.0
0.5
0
France
Hydro-Quebec
England
Ontario Hydro
Italy
Mexico
U.S.
GP4778

Figure 8

COMPARISON OF COST & EFFICIENCY
FOR EMISSION CONTROL



The CHAIRMAN. Thank you.

Mr. Disbrow, yesterday EPA Administrator Thomas on behalf of the administration stated that, and I quote from his testimony, "We do not yet believe that the current state of knowledge can sustain any judgment with respect to the level of emission reductions needed to prevent or eliminate damage." Do you agree with that statement?

Mr. DISBROW. Yes, I do, sir.

The CHAIRMAN. Mr. McCormick.

Mr. MCCORMICK. No, I do not, Mr. Chairman.

The CHAIRMAN. Mr. Mannella.

Mr. MANNELLA. I believe that our work in this area would lead to an agreement with that statement.

The CHAIRMAN. He added in his statement yesterday this is true even for the area of greatest scientific understanding, sulfur emission and surface water acidification in the area of the impact of acid deposition on forests. We have yet to determine if a cause and effect relationship exists. Do you agree?

Mr. DISBROW. Yes, I do.

Mr. MCCORMICK. Mr. Chairman, in Western Europe there is significant evidence that ozone is the bad actor in the forest die back. Ozone is a—I am sorry. Hydrocarbon emissions are a precursor of ozone formation, so we would be dealing with different technologies and different pollution control we are talking about as far as die back.

The CHAIRMAN. But do you think there is a proven cause and effect relationship?

Mr. MCCORMICK. Enough to cause the West German Government to take some fairly drastic action, including trying to slow down motorists on the Autobahn.

The CHAIRMAN. That will be the day, when that happens. [General laughter.]

Mr. Mannella?

Mr. MANNELLA. I believe that the interpretation of the work that I have seen would suggest that there is no quantitative structure for that relationship. There may be evidence of a qualitative relationship.

The CHAIRMAN. Mr. Disbrow, in your prepared testimony you state that current trends in the utility industry strongly suggest that new capacity requirements may not be built in time to meet projected capacity needs for the mid-1990's. Later in your prepared testimony you state that many utilities have canceled or abandoned the construction of large base-load facilities and are now unlikely to undertake major new construction programs.

What, in your judgment, is the reason why your company or the electric utility industry generally is unlikely to undertake construction of new coal-fired electric power generation to meet electricity demands in the mid to late 1990's?

Mr. DISBROW. Essentially the financial problems of the industry, current and prospective, which would be exacerbated by mandating clean coal or scrubber retrofits on a current basis.

The CHAIRMAN. Is scrubber retrofit a major problem at the present time?

Mr. DISBROW. Well, I think it is a combined problem of ability to finance, and given a limited capital base that we can raise, what will happen with acid rain legislation if it comes to pass?

The CHAIRMAN. Well, if I were to summarize my impression of your testimony, you are saying we cannot do both at the same time, let us do one, but do not require us to do the other.

Mr. DISBROW. That is correct.

The CHAIRMAN. To what extent can increased electricity demand be satisfied by life extension?

Mr. DISBROW. That would be very hard to quantify. Life extension would have to be determined on the basis of the individual plant characteristics, but I would judge there would be a considerable opportunity there to extend the life of existing facilities with preference to immediate construction of new facilities.

The CHAIRMAN. Was your company's decision to proceed with pressurized fluidized bed development rather than another technology influenced by concerns for compliance with new source performance standards?

Mr. DISBROW. Yes, it was.

The CHAIRMAN. You pointed to the same fact that a number of others have that the submittals under the DOE clean coal technology program do not include retrofit projects. What in your judgment is the reason for that?

Mr. DISBROW. Well, I think there are a number of reasons. One is that as the request was made, and as the understanding developed that these would not be grants but rather loans, and the loans might be repayable, which increased the uncertainty of the recovery of the State regulatory commissions. Second, there was the requirement that we prepare broad market analyses of each of these opportunities, which is very difficult and time consuming.

And third, that we would have to undertake a broad scale review of the potential contribution to the environment, and the uncertainty in the smaller expenditures and the smaller projects and the time and troubles that we have gone through in filing a proposal. It was simply not worth the gamble.

The CHAIRMAN. Can I restate that to be sure that I understand what the thrust was? You could accept that burden or proposers could accept that burden with respect to new technologies, but would not or could not accept that burden with respect to retrofit?

Mr. DISBROW. That is correct.

The CHAIRMAN. Now, Mr. McCormick, in your judgment, is the mandate for the clean coal technology program broader in scope than the demonstration program set forth in the special envoys report?

Mr. MCCORMICK. No, I think they match pretty well, Mr. Chairman.

The CHAIRMAN. In the longer term, is the trend toward upgrading and not replacing oil or gas boilers in the national interest from the standpoint of achievement of either energy or environmental policies? And if you want to separate oil and gas in your answer, please do.

Mr. MCCORMICK. Well, Mr. Chairman, I look at boiler life extension as a consumer savings, and therefore the environmental community should support boiler life extension, but I also see it as an opportunity to encourage the reduction of emissions simultaneously, because if a utility is going to capitalize boiler life extension and some time in the future an acid rain control program mandates emissions reductions for that boiler once its life is extended then the economics of the boiler life extension is seriously threatened.

Conversely, if a mandate for emissions reduction is delivered upon an electric utility company through an acid rain control program, if the boiler is 25 or 30 years old, it is at that point that the company is going to have to retrofit the boiler and upgrade it or retire it. That is an additional expense to the utility, and ought to be factored into the cost on the dollars per ton of SO_2 removed.

So, one way or the other, Mr. Chairman, I believe the environmentalists and the consumers can have it both ways. We can reduce the emissions, but we can also reduce the burden electric utility customers pay when new construction is added to the rate base.

The **Chairman**. Now, Mr. Disbrow said we can afford to do one but not the other. We cannot do both simultaneously. You are in effect saying, we can do both simultaneously.

Mr. **McCormick**. I think from a business standpoint you would have to consider one or the other. If you extend the life of the boiler, you have got to consider the down side of having emissions reductions imposed on you later. If you have emissions reductions imposed on you now, I think you have got to take the opportunity to upgrade the boiler.

The **Chairman**. Mr. Mannella, in the middle of page 2 of Mr. Yeager's statement I see a listing of points, the second point of which is accelerated commercial demonstration and implementation of these technologies by regulated utilities will require cost sharing and other incentives not available today. Why?

Mr. **Mannella**. Why are they not available today?

The **Chairman**. No, why does it require cost sharing and incentives that are not available today?

Mr. **Mannella**. Because I think, as has been touched upon by Mr. Disbrow and other witnesses, the economics for the utility to make investments in new technology are not necessarily that attractive.

The **Chairman**. Well, being attractive does not mean being attractive or not attractive. This is not really a scenario for a love scene. This is a question of whether or not it can be done.

Mr. **Mannella**. Well, as we tried to spell out elsewhere in the testimony, there is considerable cost associated with each demonstration above the other alternatives that a utility has to obtain the same amount of power, because demonstration plants are more expensive, because their maintenance is more expensive, and their instrumentation is more expensive and extensive, and there has to be some reasonably comfortable feeling on the part of the management of the utility that they will be allowed to recover those costs or have the risks shared by somebody in order to proceed.

The **Chairman**. Is the concern over whether or not the State regulatory commissions will permit the recovery of cost?

Mr. **Mannella**. I think that that is a large part of it.

The **Chairman**. Is that a part of it, Mr. Disbrow?

Mr. **Disbrow**. Yes, it is.

The CHAIRMAN. Mr. McCormick?

Mr. MCCORMICK. I understand it is.

The CHAIRMAN. On the top of that page it is stated, "In spite of the progress achieved, the political focus is shifting from new sources to the more difficult problem of existing facilities." Now, I do not mean to be unduly sensitive, but Mr. Yeager says the political focus. Does that indicate all the decisions being made by the utilities in this area and all the scientists in this area are political decisions?

Mr. MANNELLA. Well, I do not know what Mr. Yeager had in mind when he wrote that. I do not believe, though, that that was the sentiment that he intended to convey. Again, elsewhere in the testimony and in the detailed attachments, in talking about refurbishment, he points out that in the existing facilities, in the retrofit and the life extension we really know very little about the operating characteristics, the reliability, the cost, and what have you associated with that kind of option. That has been done to a very limited extent.

The CHAIRMAN. I am concerned with the line that runs through a lot of the testimony we received not only in this hearing today but we got last year as we held the hearings with respect to the general conditions and general problems of the electric utility industry, is this oft repeated statement that we are going to run into a crisis in the early 1990's, that we are not now making commitments of the scale and nature necessary to meet projected growth and load demands by the early 1990's.

Now, recognizing that every one of these problems is indeed a problem, is there a way in which we can meet the load growth requirements by the 1990's? Is there something we ought to be doing now, not only in terms of the environmental cleanup, but also in terms of the commitments of the utility industry to making the judgments now that will yield the results in the early 1990's.

Mr. Disbrow, as I understand your statement, you are suggesting, give us a little breathing room and we will go ahead and develop the pressurized fluidized bed combuster, and then we will be ready some time in the 1990's but not the early 1990's to meet our needs by that technology. Am I summarizing correctly?

Mr. DISBROW. There would be another alternative available to meet the needs in the nineties.

The CHAIRMAN. But it is not an alternative that is available today.

Mr. DISBROW. That is correct.

The CHAIRMAN. And by your own testimony commitments need to be made today for the early 1990's.

Mr. DISBROW. Yes, sir.

The CHAIRMAN. Now, how do we close that gap?

Mr. DISBROW. I think the basic question to be answered is, how do we remove uncertainty? I think that is the key question to the planning for the nineties, whether it be pressured fluidized bed or conventional pulverized coal-fired plants or whatever. The uncertainties today in terms of ability to recover capital or enough return capital are in great question, and I think that single question has chilled the industry's enthusiasm for new construction of any kind.

The CHAIRMAN. Mr. McCormick.

Mr. MCCORMICK. Mr. Chairman, I am finding it difficult to think of the electric utility industry in the nineties as we have in the eighties, and I do not see the industry as monolithic either, because obviously some sectors of the Nation are continuing to expand economically where other sectors, particularly the Midwest, are not. If I were an electric utility planner, in looking at a 15-year plan, considering the possible need for new capacity, I would have to think in terms of $1,500, $2,000, $2,500 a kilowatt hour, and is the electric utility industry anxious to spend those high dollars when there are cheaper ways to offset those expenses?

I think they are beginning to find that load management, gas-fired combined cycle turbines, and other ways are dampening this demand for new capacity and providing this hiatus. Georgia Power Co. said they will not add new capacity until the year 2007, but they must be using load management and other means to try to handle the peaks, so there are much cheaper ways, including the utilities becoming more active in energy conservation, particularly electric motor and appliance efficiencies, and in any way they can stretch this hiatus as long as possible, because during this time there will be some congressional action on an acid deposition program. Whether it is a one-or-two phase program, I think it is going to be in the neighborhood of a 10 million ton reduction, and rather than committing dollars to new capacity, the industry is going to have to commit dollars to old boiler retrofit and emissions reductions and scrubbers on the plants that are required to reduce.

The CHAIRMAN. Your suggestion to Mr. Disbrow in reducing the uncertainty is, accept the inevitable?

Mr. MCCORMICK. Well, I like to say, Mr. Chairman, that for the Midwest the question of acid rain debate is not what if. It is a question of what now.

The CHAIRMAN. Mr. Mannella.

Mr. MANNELLA. Well, Mr. Chairman, from the standpoint of EPRI we develop our program in response to the perceived needs of our member utilities, and our goal is to have an array of technical options for them to use as part of their decisionmaking process when that decision point comes, when each individual utility makes its decision as to how it will meet its low growth, leaving plenty of latitude for the kinds of things you have heard, such as load management, if that is an attractive option, and other alternatives.

However, I seem to recall at a hearing that you had not so long ago where you asked that question to a number of utility executives. I think the title of the hearing was "When Will The Lights Go Out", and the answer that you got was that the utility industry will not let the lights go out, but the means that they employ to keep them burning at any given point in time may not necessarily be the most cost effective that might be available if we had time to develop the new technologies. Now, is that an accurate recollection on my part of the response that you got?

The CHAIRMAN. I think that is fair, although I would have to say also that while recognizing the extreme difficulty the utility industry is facing on a whole host of fronts, not just one, but several fronts at the same time, leads me to believe that perhaps we may see utility management beset with those problems deferring judgments because of uncertainty or because of the bewildering array of alternatives, choosing the least risk option that gets by now, but makes it too late to meet need, no matter what their intention may be, and that we will have spot shortages in the early 1990's.

Mr. Disbrow.

Mr. DISBROW. May I clarify two things? Without wishing to be argumentative, I think plant life extension obviously is an option for the nineties and beyond. However, it is not a single option. This is a very complex issue, the new capacity life extension and so on. It is going to be a tradeoff between capacity need versus consumer demand, and most importantly, the economics of the various decisions. I don't think you can put all of your eggs in the plant life extension basket or the new plant construction basket. I think it is going to be a combination of both.

Earlier I think there was a confusion in my response that you can't do both. I was not suggesting that retrofit technology and development of new technology argued with each other. What I was suggesting was, we can't work on the new technology, be they retrofit or brand new technology, and respond with the sulfurization limits if they are put on in some acid rain legislation. That is the thing we cannot do both of.

The CHAIRMAN. Is it a timetable question?

Mr. DISBROW. Well, simply, we would not have the financial resources to do both.

The CHAIRMAN. You can't afford to do both?

Mr. DISBROW. That is correct.

The CHAIRMAN. Senator Murkowski.

Senator MURKOWSKI. Thank you very much, Mr. Chairman. As you know, I have had a lingering interest in the marketability of low sulfur coal, and I am curious if any of the witnesses would care to respond to the supposition that while we understand the Clean Air Act requires the utilization of scrubbing in all new plant construction, but is there no incentive to use low sulfur coal if it must be ascribed to basically the same scrubbing technology as higher sulfur coal? And I am questioning whether you agree with the reference under the interpretation that both have to have the same or relatively high technological application, which acts as a disincentive to low sulfur coal, or could.

Mr. MCCORMICK. I will try to answer this way, Senator. The percentage reduction provision of the Clean Air Act requiring 90 percent removal when using high sulfur coal, 70 percent low sulfur coal has had a very positive effect in the Western States in that it helped the State air regulatory authority to bring down the emissions in a plant that was proposed, say, in the early 1970's and went on line in the early eighties from the SIP, which was 1.2 pounds for new sources down to something around 0.6 or 0.7.

That dropped the total emissions load in that air quality control region sufficient to allow additional economic development in that region, so if we allow up to 1.2 for new plant in the West, it is very likely that we would fill that air quality control region's allowability, so the percent reduction has actually provided room for additional economic growth, and I think that is a great benefit.

Mr. DISBROW. Obviously in some instances, Senator, there is an opportunity for direct substitution of low sulfur coal for higher sulfur coal without any technological retrofit. However, in dealing with the technological retrofit, it again becomes a question of economics. What is the premium in the low sulfur coal versus the additional cost of handling sludge disposal and so on, a fluid gas scrubber, so it is an economic question as to what the proper choice is?

Senator MURKOWSKI. Well, is there a disincentive in the sense of the statement of the previous witness? The inference was that, well, you could fill up your allowable percentage of pollutant or whatever the terminology might be, allowable by using low sulfur coal, but the concern I have is, you indicate the economics of it, and I am concerned with the proposed regulations being a disincentive because of the same technological application and treatment on both types of coal.

Mr. McCORMICK. Mr. Chairman, I don't know that there is very much coal in the West with the sulfur content and BTU content that would allow something to approximating 0.9 pounds of SO_2 burned without controls, but building a powerplant in the West, obviously the supply of coal for that plant will be low sulfur coal. But again, still not low enough and high in heat content enough to allow something approximating what the percent reduction provision is providing now.

So I do not see percent reduction as a disincentive for using Western coal in powerplants located near that source of fuel.

Senator MURKOWSKI. Well, if I can clarify for my own understanding, it is generally the impression that if you have low—the lower the sulfur content, the lower the BTU. Is that generally true?

Mr. McCORMICK. It is hard to have a rule of thumb when you are talking about that.

Mr. DISBROW. I think the confusion is between subbituminous coal and bituminous coal. There are vast quantities of coal in Utah that have sulfur of less than 0.5 percent, and a BTU of over 11,000, in contrast to the Wyoming coals, which have very low sulfur and are down in the 8,000, 8,400 BTU category.

Senator Murkowski: But you are still dealing with low sulfur coal, and you have two types, bituminous and subbituminous.

Mr. DISBROW. Both available in the West.

Senator MURKOWSKI. Both available in the West. How do you propose—what suggestions might you have for regulatory or legislative changes that would address a combination of issues. A, you have two types of coal. You have the economics of the BTU availability on subbituminous, which is lower than bituminous, and then you have the incentive to use up the so-called allocation by bringing in subbituminous coal, and as you develop regulations which are designed primarily to improve air quality. How do you equate to all of those factors so you have equity in the application of the proposed regulations which do not act as a disincentive to any one type of coal particularly because they have to balance out with the economics? If you burn coal, are you better off burning more bituminous to get the BTU, or having more subbituminous to have less sulfur? You people are the experts.

Mr. **Disbrow**. I am not prepared to respond to that.

Senator **Murkowski**. Could you have someone provide something for the record that would address that dilemma that I think is before us?

Mr. **Disbrow**. I can do that.

Senator **Murkowski**. With regard to low sulfur coal?

Mr. **Disbrow**. I would be happy to attempt to do that.[1]

Senator **Murkowski**. Thank you, Mr. Chairman.

The **Chairman**. Senator Ford.

Senator **Ford**. Is the Senator from Alaska drawing a line between high sulfur coal and using low sulfur without getting into the scrubbers or something of that nature?

Senator **Murkowski**. Well, not really. My intention is to focus in on the low sulfur coal and the two types that we have, and then the economics of, is it better? Do you have to put in the same scrubbing capability?

Senator **Ford**. Well, I do not want you to lose sight of when you are talking about economics as it relates to the generating facility. I want you to also look at economics as it relates to the employees and local communities.

Senator **Murkowski**. Well, that applies to wherever the coal is coming from.

Senator **Ford**. In our State, if you go to a "low sulfur coal" that reduces our coal reserve in Kentucky to the usable coal reserve by almost 70 percent, so then you have those in the high sulfur area that are out of work, and then you say, well, they will be made up elsewhere. They just employ those who have been laid off. We have got 0.5 SO_2 coal in Kentucky with 13,800 Btu, but not a great deal of it, but we do have it, and you could use that, so there is an argument that you could get into that you burn coal that wouldn't need scrubbers.

Senator **Murkowski**. It is not my intention to make that kind of an implication. I would assume that the geography and transportation distance would dictate the economic preferability. In other words, if you are talking about Kentucky coal, you only move it so far in the economics.

Senator **Ford**. We sell in 20 States.

Senator **Murkowski**. But I assume you only move it so far economically West before you come up with the reality of Western coal.

Senator **Ford**. That is correct. Let me ask a question of the two gentlemen beside Mr. Disbrow, in Mr. Disbrow's statement on page 15, I think it is, he calls for another statement of interest solicitation to determine the extent of interest in retrofit technologies, and to consider using the $350 million left in the Clean Coal Reserve for these projects. John, do you or Mr. Mannella have any comment? How do you feel about that? Either one.

Mr. **Mannella**. Well, we would support it, Senator Ford. In Mr. Yeager's testimony, I think, on page 10 we try to present what admittedly is a very kind of difficult analysis of the response of the BON because we only had the titles and the brief summaries, but it did seem to us that in the retrofittable emittable control options the response was very limited. This has been touched on earlier by Mr. Disbrow, and we do feel that another solicitation and perhaps with some streamlined provisions of response to facilitate the proposing of the kinds of technologies would be very beneficial.

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[1] Response not received for the record.

Mr. McCormick. John, as you know, our organization has been very actively supportive of the clean coal technology reserve, but it was when the Congress added guidelines to it that we really began to find votes among environmental legislators to support it, and prior to that I do not think the clean coal technology reserve would have passed the Congress. If the final product coming to the Hill before the DOE signs off on these demonstration projects do not include enough of these retrofit technologies, I do not think that is a failing of the clean coal technology reserve program because it started off with the DOE saying that this is really a loan program, not a grant program, and that might have caused some prospective applicants to back away.

I think it is at this point if we find that there are not enough retrofit technologies in the first 400 million to go back to DOE and say try again. Now we have got the DOE's energy research advisory board having provided then Secretary of Energy Bedell with a universe of clean coal technologies. EPRI submitted to DOE a list of 25 technologies, many of which are retrofit related. Bring these two together and ask DOE to augment the list of 51 with some of these technologies that were not submitted. But we know that there is interest. And then offer them up as Government-funded research projects. And I am sure you are going to get States like Ohio, Illinois, and Kentucky to cost share as well as the utilities in those States.

Senator Ford. They have already provided funds to get into it.

Mr. McCormick. There is no lack of technologies ready to be demonstrated on a commercial basis. What we have to do is force it to happen, use the first 400 million to move these technologies out, and then see if there are additional needs that the 350 million can address and, I think, stay with the program until we exhaust the 750 million, but the highest priority being emissions reduction research.

Senator Ford. As I look at it, 5 of the 51 are retrofit, and one of those is for a fertilizer plant. We really did not get the kind of solicitation results needed, and I am inclined to agree with Mr. Disbrow's statement totally.

Mr. Mannella, in Mr. Yeager's statement, in figure 7 of your testimony or his testimony you show that U.S. invests less in electric power-related research and development on a percentage of gross revenues than Mexico, Italy, Ontario, Hydro England, Hydro Quebec, and France.

Does this chart reflect or include Federal research and development expenditures in those areas?

Mr. Mannella. I do not believe it does, Senator, but I would like to double check that and provide that for the record.[2]

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[2] Response not received for the record.

Senator **Ford**. Would you do that, and give us a statement for the record, and I think in Mr. Yeager's statement that you have handled so well here this morning would you elaborate a little bit as to why you think that the BON that DOE issued discouraged would-be participants?

Mr. **Mannella**. I think that some of the requirements in the BON for information on market viability on environmental impact and what not was just too onerous for certain of the smaller projects, and in particular we had mentioned from time to time during the 2 years where the program was under discussion up on the Hill and in hearings and what not we had talked about trying to facilitate the response from smaller organizations and with smaller dollar types of projects, many of which would fall into coal cleaning and some of the retrofit areas with things like a 5 percent small business setaside, which is fairly standard in Federal procurement and other departments and what not, or with a short form or an accelerated form.

For reasons which frankly I do not understand DOE chose to go with a one size fits all type of approach, and I think that the inevitable negative result of that was that many of these projects just simply fell off the list.

Senator **Ford**. I think Mr. Disbrow is already on record with a long explanation, and I will not get into that, so we will forego that, but let me ask this question. If acid rain control legislation is, let us say, further considered by the Congress, what kind of timetables for compliance should be considered so as to ensure we receive the greatest possible benefit from industry's use of new clean coal technologies? I will ask those representing industry here today to respond to that, if you will. Mr. Disbrow?

Mr. **Disbrow**. I have a hard time responding to that without knowing what the emission requirements would be in acid rain control legislation, but it is clear to me that we need additional time for technological development unless we are to adhere to full gas desulfurization systems. I would feel that minimally it would be 1995 and perhaps a year or two later before we were in a position to really do very much with new technology. Technological development simply takes time.

Senator **Ford**. Would you take the Senate bill and look at that and respond for the record?

Mr. **Disbrow**. I will, sir.[3]

Senator **Ford**. Mr. Mannella.

Mr. **Mannella**. I would like to associate myself with Mr. Disbrow's remarks.[3]

Senator **Ford**. Would you look at the Senate bill and give us some kind of projection? The testimony yesterday and in the last 2 days have stressed the need for time, and I do not think any of us are trying to delay just for delay's sake. I hope I am not. But I think there is a world of possbilities, and that we are just not getting to that. In order to make it better, we can rush, I think, into a lot of things, and begin to look at what might occur if we use present technology.

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[3] See responses to question 8 in appendix II.

I do not believe I have any other questions, Mr. Chairman.

The **Chairman**. Senator Warner.

Senator **Warner**. Thank you, Mr. Chairman.

I share the sentiment expressed here by others today on the question of the retrofit, and I am wondering if we should see whether or not we could recommend that DOE have a second round of solicitation proposals, and have those proposals specifically targeted at retrofit technologies. Do any of the three of you wish to comment?

Mr. **Disbrow**. I would think that a good idea.

Mr. **McCormick**. I think this committee ought to begin encouraging DOE in that direction.

Senator **Warner**. Now, I am not hearing, and I definitely want to hear. Would you be kind enough to repeat that answer?

Mr. **McCormick**. I think this committee ought to begin discussing that with DOE today. I think the idea is, the idea to create the clean coal technology reserve is a worthy idea that has got to be pursued to its limit, and I think if the program begins to deviate off course, this Congress can get it back on course, and I think we ought to begin now.

Mr. **Mannella**. We would support such an initiative, Senator Warner.

Senator **Warner**. Do you believe DOE's payback component of the solicitation has in any way dampened interest in proposing new technologies?

Mr. **Disbrow**. I feel it has. These are demonstration plants. They are not commercial plants. There is a need for cost sharing in order for us to be able to do this kind of work, and I think it does discourage one looking at a loan and a repayment program as proposed.

Mr. **McCormick**. Mr. Chairman, the Interior appropriation that provided the money for clean coal technology reserve was approved before the Lewis Davis report was delivered to the President. I believe the administration had not warmed to the idea of emissions reduction research until the Lewis Davis report came. It was between the two actions, Congress approving the program and the Lewis Davis report being delivered to the President, that OMB and others began looking at the clean coal program as a loan program. That was an unfortunate mistake, and I think they have tried to correct it, but they did put a chill on the numbers of applications submitted.

Mr. **Mannella**. That is my impression also, Senator. I do not have any specific information that I can point to where a proposer specifically changed his mind because of that, but we were in contact with many people during the proposal preparation period. These are very expensive proposals to prepare, and I think that there was enough confusion and enough time lost and what-not that there were some proposers that just simply could not sustain their effort all the way through to the closing date, and more or less gave up, if you will.

Senator **Warner**. One last question. Again, in the area of the retrofit technologies, you know, it has to be your determination whether or not to go back and try and retrofit these plants, and what specific changes in regulations or specific financial incentives should we consider?

Mr. DISBROW. In the development of the technology?

Senator WARNER. Yes.

Mr. DISBROW. I think Federal grant cost sharing is necessary to foster the development of retrofit technology. In terms of deployment, there is some concern, I think, on our ability to recover the amounts expended from the State public utility commissions.

Senator WARNER. Any other comments?

Mr. MCCORMICK. Mr. Chairman, if you look at the acid rain control program with a 10 million ton reduction requirement, and that having something like a 10-year time frame, during that 10 years, Mr. Chairman, there will be many utilities that go beyond their 30 or even 40 year life of operation. At some point in time the Congress is going to have to catch up with plants that continue on line longer than the 95th Congress thought they would because the Congress then put the pressure on new sources, not existing sources, because they did not feel it was economically prudent to require scrubbers on all plants.

Well, during the 10-year implementation of an acid rain program, a boiler achieving its maturity rather than reducing its emissions by putting on a scrubber or some clean coal technology could trade with the power plants that are reducing emissions under the acid rain program, and contribute some amount of money to the emissions reduction in an acid rain program, and therefore get out from under having to put emissions control on its old boiler while it continues its use for perhaps another 20 years, and in the Clean Air Act we are trying to encourage emissions trading, so we already have a mechanism in place, and I will say this again.

If the Congress requires a 10 million ton reduction program, I believe very strongly, Mr. Chairman, that Congress will also have to provide cost sharing to offset the high capital cost of those scrubbers, and if the utilities in the west are really opposed to a per kilowatt hour fee imposed on utility bills, perhaps we could look at the fairly small SO_2 emissions tax, which rewards utilities who have already made the investment in pollution control, let them pay a smaller fee, and for companies that have higher emissions, they will be reducing their emissions over time with the acid rain control program.

It turns out if you charge something like a 2½ cents per pound SO_2 tax, it would almost be equivalent to about a 1.4 mil per kilowatt hour fee, which is a fee that is half of what Senator Glenn was suggesting several years ago, and so I think we have got to be more creative about how we are going to help the utilities offset the high cost of scrubber retrofit, but this may be one approach.

Senator WARNER. Should the aging facilities be required to meet an NSPS or some lesser requirement?

Mr. MCCORMICK. I would hope not, Mr. Chairman. I think that is overkill. I think the utilities could achieve something like a 1.2 pound cap, and allow those old boilers to trade within the State to find those emissions reductions.

Senator WARNER. Thank you, Mr. Chairman.

The CHAIRMAN. I am still concerned about one thing. More than one, but one in particular. And that is, I see both the coal industry and the utility industry projecting increased electricity generation from coal-fired facilities and increased consumption of coal. Between now and 1995, I do not see the capital commitments being made to the construction of facilities that are going to bring that coal, and if indeed the projections are correct there will be a massive increase in the use of coal over the next decade, not just at the end of the next decade, and yet there is no capital commitment now to the plant construction that is going to utilize that coal.

Now, if indeed that is correct—well, first of all, let me ask you this question. Is that correct, Mr. Disbrow?

Mr. DISBROW. I believe there will potentially be shortages regionally, perhaps nationally by the mid to late nineties. Currently there is an imbalance between supply and demand, but I think that is going to be transient, and as they come into parity we will start to see possibly some shortages, but again, I believe the key question is the uncertainty of if you build any form of plant embracing any form of technology.

The CHAIRMAN. First of all, I want to understand whether or not there is a time gap.

Mr. DISBROW. I believe there is a developing time gap.

The CHAIRMAN. Mr. McCormick.

Mr. MCCORMICK. Mr. Chairman, these issues are like ships in the night. Some of them may start bumping into each other in the harbor. I think we are creating some managerial nightmares for the electric utility industry, and I think we have to take that very seriously. If it is not acid rain, it is tall stacks requirements, it is a possible sulfate standard, it is—Lord, there are several litigations.

The CHAIRMAN. I am not focusing for the moment on why. I am just trying to get at whether it is a fact that there is a mismatch between the projections of coal consumption and the utilization for electricity development and whether or not we are going to make that based upon the current decisionmaking mode.

Mr. MCCORMICK. I appreciate your question. My point is, there are pending regulations, pending litigation, pending legislation that is all going to have a very significant impact on the cash flow of utilities, the same utilities that are having to look to supplying the demand in the nineties. I think these are going to cause the utilities to look at peak load management more than new construction, and I think, frankly, that is the only way they can go until we get out of this 10 or 15 years of litigation and legislation and regulation uncertainties.

The CHAIRMAN. All right. Let me ask this question. Well, first of all, Mr. Mannella?

Mr. MANNELLA. The answer is yes, Mr. Chairman. [General laughter.]

The CHAIRMAN. Thank you. If that is correct, then the second question comes, how long does it take once you make a decision to apply a new technology? And I am not talking about just the current state of technology, not just the standard coal stack scrubbers, but if you are going to apply a different technology either to retrofit or to a new plant, how long does it take you to make that application?

Mr. DISBROW. Mr. Chairman, let me use our own pressurized fluidized bed combustion project again by way of illustration. If we were to start now, we think we could have it, the demonstration plant operational in late 1989. We will need at least 2 years and perhaps a few more years of testing to really perfect the technology, at which point, assuming everything went well, and everything else looked good, we could commit. Probably on the best track possible we could have the first commercial plant in service in 1996, 1997.

The CHAIRMAN. That you could have the first plant in service in 1996, 1997?

Mr. DISBROW. If everything went just right.

The CHAIRMAN. But that does not mean you would have achieved your percentage reductions in emissions prior to 1996, 1997, or even in 1996, 1997.

Mr. DISBROW. That is correct, if we were relying on that technology alone.

The CHAIRMAN. Mr. McCormick.

Mr. MCCORMICK. I have to agree with that, Mr. Chairman.

The CHAIRMAN. Mr. Mannella?

Mr. MANNELLA. I think that is a typical time frame for the deployment of a new technology.

The CHAIRMAN. All right, then there is not any way for us to meet near term sulfur emissions standards unless we retrofit existing plants with existing technologies.

Mr. DISBROW. That is correct, but regrettable.

The CHAIRMAN. What?

Mr. DISBROW. I said that is correct and regrettable.

The CHAIRMAN. Then we have to make a choice, do we not, of whether or not we are going to force retrofit with existing technologies on the existing plants and find a way to pay for it, or whether we are going to take the alternative and say, no, we are not going to meet emissions reductions in the near term. Is that not our choice?

Mr. DISBROW. I do not think it is quite that black and white. Some things might be done, but I do not think it is going to be a massive reduction.

The CHAIRMAN. Mr. McCormick.

Mr. MCCORMICK. Mr. Chairman, the top 12 SO_2 emitting plants in the Nation contribute 2.7 million tons of SO_2 to the air shed. They are obvious candidates for scrubbers. If we can develop over time direct line injection to reduce the cost of emissions reductions from those plants, they are too juicy a target to pass up to get only 50 or 60 percent reduction when we can get, say, 25 percent of a 10 million ton reduction from 12 plants alone, and if the nation is contributing to that, then we can move along on that time frame, and simultaneously continue to move less expensive and less effective but important clean coal technologies for the remainder of the utilities that are not quite as good scrubber candidates.

The CHAIRMAN. Mr. Mannella.

Mr. MANNELLA. Mr. Chairman, I think that we have time. We don't really have to do anything precipitous. In the body of Mr. Yeager's testimony is data from our ERAM model study which shows that the trend of reduced SO_2 emissions which began to show itself in the early 1970s will continue with the existing plant capacity that we have, and that even in the worst case scenario that is worked out in some detail there there is little likelihood of any significant increase in SO_2 emissions during the time period from now until, I believe, the year 2000.

The CHAIRMAN. Gentlemen, thank you very much.

Senator WARNER: Mr. Chairman, could I just ask one question on your line of questioning?

Mr. McCormick, do you have any comment on the National Coal Association report that emissions have continued to decline since 1980?

Mr. McCORMICK. A brief comment, Mr. Chairman. I believe that the data was weighed heavily by the new capacity brought on line in the West, and that brought down the national emission average, but in the East, where all old boilers are going to remain on line longer, I think that is going to moot the projected trends that the NCA study tried to portray. I do not see that trend. Perhaps nationally there is, but when we are talking about acid deposition it is really a regional problem, and not, say, a west of the Rockies problem for Canada, so let us say if they did that report looking at the eastern 31 States, I am not sure they would come to the same conclusion.

Senator Warner: I thank the Chairman.

The CHAIRMAN. Gentlemen, thank you very much for your testimony. I appreciate your time and your willingness to answer. There will be some additional questions to be submitted for response in writing to the record.

We will now hear from our second panel.

Gentlemen, if you will take your places at the witness table, Mr. Addison, Mr. Wootten, Mr. High and Mr. Hawkins.

Gentlemen, your entire prepared statements will be placed in the record in full. I will invite you to summarize so that we may get to the questions as soon as possible.

We will start with Mr. Addison.

STATEMENT OF EDWARD L. ADDISON, PRESIDENT AND CHIEF EXECUTIVE OFFICER, THE SOUTHERN CO., ON BEHALF OF THE EDISON ELECTRIC INSTITUTE

Mr. ADDISON. Thank you, Mr. Chairman. My name is Ed Addison. I am the president and chief executive officer of the Southern Co., which is the parent firm of an electric utility system that operates in four States in the southeast and serves electric energy to some 10 million people.

During 1985, Mr. Chairman, we burned nearly 44 million tons of coal at our powerplants, making the Southern electric system one of the three largest coal users in the United States.

I am testifying today on behalf of the Edison Electric Institute, the national association of investor-owned utilities. We appreciate the opportunity to present our views, and we thank you for having these hearings so that we can focus on this issue. I will touch briefly on several points from the longer, more detailed testimony which we have prepared.

Mr. Chairman, we believe clean coal technologies offer our Nation the promise of a more cost effective way to control power plant emissions than would be mandated by the acid rain legislation which has been proposed in both houses of Congress.

In addition, because clean coal technologies would promote the use of domestic fuel, they can provide a more secure reliable energy future for this country. These are but two of the many reasons why I believe we should look on money invested in these new technologies as productive dollars.

There are several major barriers to the development of clean coal technologies, and the first of these barriers can be found in the proposed acid rain legislation that I have mentioned. American utilities simply cannot afford to do both; that is, to pursue a Clean Coal Technology Program and to comply with acid rain proposals. That, according to informed estimates, could impose additional cost of up to $110 billion over a 15-year period. We just do not have the capital resources to do both.

In addition, the acid rain legislation proposes mandatory deadlines that would not allow us to explore new clean coal technology first to demonstrate that the more costly approach to controls is unnecessary. This question of the cost of controls is crucial for industrial and commercial customers as well as for our residential customers. American goods and services have to compete around the world, and the cost of energy is an important factor in any business. This means that we must keep the cost of our electricity competitive with energy cost in other countries.

We believe clean coal technology can help this Nation maintain a competitive edge, but the proposed acid rain legislation would do just the opposite.

For these and many other reasons, we hope this committee, which has recognized the potential value of clean coal technologies in the past, will do everything possible to encourage their development and use. Given our support for clean coal technology, it is reasonable to ask why many utilities did not submit proposals to the Department of Energy under the Clean Coal Technology Reserve Program. We have discuss this subject in the detailed testimony which we file today.

Briefly, there have been three chief problem areas. The repayment provisions raise doubts and resistance in some companies. The requirement for extensive market analysis on a nationwide basis made many companies feel they were being pushed beyond the area of their knowledge and competence and the Department of Energy requirements for information about environmental, healty, safety and socioeconomic effects were felt by many to be excessive and to add unnecessarily to the cost of preparing a proposal. So the problems were not with the concept of developing clean coal technology but rather with the way the program was presented.

We, in the Southern electric system believe, and I am confident most of our utility colleagues would agree, that clean coal technology offers this country a highly promising, cost effective way to employ our most abundant energy resource while protecting the environmental gains we have made under the Clean Air Act.

That is why we found it encouraging that this approach was a cornerstone of the recommendations that Drew Lewis presented to the President in the joint report of the special envoys on acid rain.

We see a fatal threat to the development of clean coal technology in the acid rain legislation that has been proposed because it would usurp funds that would be better invested in clean coal technology and because it imposes deadlines that will not permit the exploration of the new technology first.

It would seem much wiser to pursue the development of clean coal technology while we continue environmental research, like the comprehensive NAPAP Program that has already been authorized by the Congress. If we take this course, in just a few years we would not only have far more of the information we need to define an appropriate national strategy, but we would also have an array of new technologies to choose from in carrying out that strategy.

We therefore urge the members of this committee in the national interest to give full support to practical programs for developing and demonstrating clean coal technology and to turn aside the premature acid rain proposals that threaten to preempt both the money and the time that clean coal technology needs.

Thank you.

[The prepared statement of Mr. Addison follows:]

HEARINGS BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

EDWARD L. ADDISON
PRESIDENT AND CHIEF EXECUTIVE OFFICER
THE SOUTHERN COMPANY

ON BEHALF OF
THE SOUTHERN COMPANY
AND
THE EDISON ELECTRIC INSTITUTE

JUNE 10, 1986

I am Edward L. Addison, President and Chief Executive Officer of The Southern Company. I appreciate the opportunity, Mr. Chairman, to appear before the Committee today to present the views of my Company and The Edison Electric Institute on the issues outlined by the Committee.

The Southern Company is the parent firm of four electric utilities -- Alabama Power, Georgia Power, Gulf Power, and Mississippi Power -- that operate generation, transmission, and distribution facilities which supply energy to some 10 million people across the Southeast. Other Southern Company subsidiaries include Southern Company Services, which provides engineering and technical services to the other members of the Southern electric system, Southern Electric International, a consulting subsidiary, and Southern Electric Investments, an investment subsidiary.

In 1985, nearly 44 million tons of coal were burned at our generating facilities -- making the Southern electric system one of the three largest coal users in the United States. Thus, the issues being examined at this hearing are of special importance to us. As a major contributor to the Electric Power Research Institute (EPRI) -- the research arm of the electric utility industry -- we are participating in research into the causes of environmental acidification, the environmental effects of acid deposition, and the technologies that would be deployed for future emission controls by the electric utility industry. In addition, engineers and researchers in our companies have gained expertise in five types of flue gas desulfurization (FGD) technologies; we are directly involved with the atmospheric fluidized bed project managed by the Tennessee Valley Authority; we manage the high-sulfur coal fabric filter (baghouse) test facility for EPRI; and we have managed from its inception in 1972 the advanced coal liquefaction research and development facility -- currently supported by the Department of Energy (DOE) and EPRI -- for process development of Solvent Refined Coal and Integrated Two-Stage Liquefaction of Coal.

The Edison Electric Institute (EEI) is the association of the nation's investor-owned electric utilities. Its members serve 96 percent of all customers served by the investor-owned segment of the industry, generate more than 75 percent of all the

Testimony of Edward L. Addison
The Southern Company
(Continued)

electricity in the country, and service 73 percent of all ultimate electricity customers.

Coal is the primary fuel for electric generation and produces over 53 percent of the electricity used in the United States. The North American Electric Reliability Council has stated that in 1984 electric utilities used 655 millions tons of coal to generate electricity. They have projected that by 1994 this figure will grow to 815 million tons of coal.

Mr. Chairman, we applaud you and the Committee for scheduling these timely oversight hearings on clean coal technology development and how it relates to strategies for acid rain control. While it has been stated by many witnesses already, I must state again in the clearest terms to you and the members of the Committee that an acid rain control program such as that embodied in S.2203 or in H.R.4567 would preclude the utilization of clean coal technologies. This would occur because the mandatory deadlines in both bills would force us to to allocate all of our financial resources to complying with deadlines contained in the proposed legislation. If either bill passes in its current form, we would simply and immediately have to forego clean coal technology development. What resources we have would have to be applied to the problems of complying with this new law. Further, the timetable for clean coal technology development is such that these technologies cannot meet the schedule proposed in acid rain control legislation.

Based on the work we have done in our company and the needs of the utility industry in the future, we believe new clean coal technologies will offer the nation more cost-effective and improved ways to control emissions from coal-fired power plants. In addition, because of their utilization of domestic fuel sources, these technologies will provide a more secure and reliable energy future for our country.

POLICY OVERVIEW

As I have stated, U.S. utilities cannot afford to pursue a clean coal technology program and at the same time be required to incur major cost increases to comply with acid rain control legislation. There simply are not sufficient capital resources to carry out both of these efforts. And if the proposed acid rain control timetables are enacted, virtually all clean coal technology research, development, and demonstration by electric utilities would have to be curtailed.

Clean coal technologies are expected to offer the utility industry many benefits. These may include fuel flexibility, modular and incremental construction of power producing facilities, and a potentially higher level of emission controls.

Demonstration of clean coal technologies must proceed immediately if there is to be a family of technologies available for utilities to employ by the latter part of the 1990s. Today, our industry has operating experience with only one clean coal technology: coal gasification combined cycle generation. Our experience amounts to approximately 24 months, and that is not sufficient time to have demonstrated, tested, and evaluated all of the plant components so that utilities can make reasoned decisions about future applications of this technology. Electric utilities have little operating experience with atmospheric fluidized bed combustion, none with pressurized fluidized bed combustion, and very little to none with most of the other advanced clean coal technologies. Certainly, I cannot commit my company, Mr. Chairman, nor do I believe most companies in the industry would commit, to a new technology that has not been adequately demonstrated and does not have vendor guarantees.

We want our industrial customers to provide competitive goods and services in the international market and that means the cost of our electricity must be competitive with that provided by utilities around the world. We believe clean coal technologies will allow U.S. utilities to maintain a competitive edge. We hope this Committee will pay careful attention to the negative impact of proposed acid rain controls on the economic competitiveness of the electricity produced in the United States.

I also noted that clean coal technologies provide fuel flexibility. This flexibility forces a more competitive fuel procurement market for utilities which, in turn, helps to reduce the cost of power production. A broadened fuel market is also one which is likely to be characterized by the production and use of more domestic coal. Conversely, if we must comply with regulation that limits our fuel flexibility through an acid rain control program, shifts in fuel demand would result and utilities would be forced to pay premiums for low-sulfur fuel, thereby increasing costs. It's predicted that such shifts in demand would create many dislocations and significant losses in coal industry employment.

Testimony of Edward L. Addison
The Southern Company
(Continued)

I touched earlier on what our company has done to develop clean coal technologies. We are not alone in this work. I'd like to outline briefly the efforts of some other utilities. Southern California Edison Company has taken an aggressive lead in the development of the gasification combined cycle technology at its Cool Water Plant in Southern California. Illinois Power Company has also been a gasification leader with KILnGAS technology at the Wood River Station. This month, Northern States Power Company in Minneapolis will begin operation of the first utility-scale atmospheric fluidized bed combustion boiler in the nation at the Black Dog Station. American Electric Power Service Corporation has spent the past 10 years developing pressurized fluidized bed technology as an additional means of reducing emissions from coal-fired power plants. Florida Power & Light Company has also participated actively in pressurized fluidized bed research over the past few years. New York State Electric and Gas Corporation and Pennsylvania Electric Company jointly operate the Homer City Station in Pennsylvania which has conducted major coal cleaning tests during most of its operational life. Utilities in this country also have pursued -- independently of EPRI -- coal cleaning, coal-water and coal-oil mixtures, magnetohydrodynamics, slagging combustors, and a variety of other technologies.

In short, Mr. Chairman, research is under way on many clean coal technologies that offer the prospect of better environmental compliance than existing technologies, lower construction and operating costs because of modular construction and fuel flexibility, and incremental capacity sizes that are appropriate to meet increasing utility generation needs. We believe this is an area in which federal funding and policy is in the national interest.

U.S.-CANADIAN ACID RAIN AGREEMENT

In reviewing the recommendations of the Joint Report of the Special Envoys on Acid Rain, I believe it's important to note the recognition that "..our mandate was not to find a final solution to this bilateral problem, but to find ways in which our two countries can begin to move together to deal effectively with this vexing issue..." (page 41).

The initial recommendation in the Joint Report, to expand the control options available through a clean coal technology demonstration program, is wise public policy that should be implemented immediately. Electric utilities stand committed to the most cost-effective means of needed SO_2 and NO_x control and are willing to actively participate and co-fund technology demonstrations by spending productive dollars in efforts to broaden the range of technologies currently available. Federal co-funding is a proper role for the government, though DOE must recognize that co-funding does not mean a loan of federal funds. Earlier this year, there were major policy disagreements over DOE's intent to recover federal dollars in its clean coal solicitation.

Other recommendations in the Special Envoys' report -- such as the review of existing law and programs, the creation of advisory groups, and continued discussions between the leaders of the two countries -- establish useful goals. The report calls for information on a means of measuring dry deposition, watershed data, causes of surface water acidification, potential links between forests and acid rain, and materials damage. Research is now being conducted, primarily by EPRI and the National Acid Precipitation Assessment Program, that should be very helpful. Above all, we believe the principal recommendation -- a cost-shared and co-funded technology demonstration program -- needs immediate and careful attention by the Congress and the Reagan Administration.

CLEAN COAL TECHNOLOGY SOLICITATION

Our review of the submittals to DOE under the Clean Coal Technology Reserve is limited to the public abstracts prepared by each organization and whatever additional information that can be learned directly from those companies since DOE's procurement regulations inhibit discussion of a submittal's content.

However, it's clear from what we have seen of the submittals that the electric utility industry continues to make a vigorous effort in regard to new technologies. There are 21 utilities involved in clean coal submittals to DOE as listed in Table 1. Some of these are the prime sponsors of a project and will be reflected as such on publicly available lists, while others are supporting a specific project and can be identified by reading the public abstracts.

In general, proposed projects address technologies which can be used for retrofit, repowering, and new construction. The fluidized bed projects, and there are several of both the atmospheric and pressurized versions, tend to lend themselves to repowering and new construction. However, the technological evaluation cycle for all of these projects will not be completed by the time proposed acid rain legislation would require utilities to meet new emission standards. And much of existing technology is not designed to meet NO_x standards proposed in H.R. 4567 and none will meet control requirements proposed in S.2203. To meet these standards in a manner which will allow American industry to remain competitive virtually mandates the development of new technology.

I also would like to point out that some companies, such as Wisconsin Public Service Corporation, are proceeding with technologies not submitted to DOE with one of the major reasons being DOE's submission requirements. Almost certainly, a number of electric utilities and other corporations did not submit proposals because of the paperwork requirements and confusion about repayment. The Draft Program Opportunity Notice (PON), issued by DOE on January 30, 1986, probably hurt many potential projects because of Section VI-4 which set forth how DOE proposed to recover federal funding. The language said, "The Government intends to recover up to its contribution from the proposer out of revenues during the period of performance, out of net revenues received if the project is operated by the proposer beyond the period of performance...." We believe that provisions of the Draft PON had a very negative effect on companies considering proposals, and changes issued in the final PON and the ongoing discussions concerning repayment did not overcome this problem.

In addition to the repayment provisions, draft and final PON requirements for market analysis impacts and environmental information were overwhelming to many companies. As a regulated franchise, we understand the technology and energy needs of our system and similar needs for neighboring companies. However, the PON required that we provide a detailed analysis of the potential for a technology to penetrate the utility market nationwide. DOE was unreasonable to expect that a utility such as ours, operating in the Southeast, would be knowledgeable about the clean coal technology needs or power system requirements of utilities in Washington State, Wyoming, Ohio, or Connecticut, for example.

DOE also asked for detailed information about the environmental, health, safety, and socioeconomic (EHSS) aspects of each technology. We felt that most of these requests were premature and unreasonable at this stage of technology development and added unnecessarily and substantially to the cost of proposal preparation.

BARRIERS TO CLEAN COAL TECHNOLOGY DEVELOPMENT

There are a number of barriers at several levels of government to the immediate utilization of clean coal technologies. Accelerated demonstration of clean coal technologies can occur only if the government is willing to share the risk of developing new technologies with the private sector. Under DOE's proposed regulating provision, a utility which has subjected its ratepayers to risk-sharing (for the utility's share in a demonstration project) would be asked to repay the government if the project succeeds. Clearly, the utility's ratepayers will benefit if the demonstration project is successful. However, so will ratepayers (who are also taxpayers) in other utility systems that ultimately put into place these demonstrated technologies. We believe the government's portion of a project is that portion of risk-sharing which the government bears on behalf of all ratepayers and taxpayers. Thus, government's contribution should be viewed as a sound leveraged investment, serving as a catalyst to provide incentives stimulating the development and demonstration of technologies beneficial to the entire country.

A second area where government action is needed, if clean coal technologies are to be developed and demonstrated, concerns existing environmental regulations. Many of these regulations are so rigid or are applied so inflexibly as to discourage innovation. For example, current new source performance standards (NSPS) require a fixed level of control technology performance. In many cases, these standards preclude use of technologies that may remove a marginally lower amount of pollutants but produce substantial economic and energy savings. EPA has the authority to adopt more flexible NSPS -- for example, by writing different standards for different types of boilers, by modifying the Commercial Demonstration Permit (CDP) regulations to allow additional technologies to apply for CDPs, or by granting waivers to allow implementation of clean coal technology where appropriate -- and the agency should signal its willingness to do so.

Also, because sources involved in demonstration projects will likely experience problems with pollution control equipment operation, EPA should make clear that -- as long as public health-based air quality standards are met during the demonstration period -- flexibility will be afforded with respect to compliance with emission standards. Among other things, EPA should move forward with emission trading and expanded "bubbles" to encourage these innovative technologies.

COST COMPARISONS

The current technologies which serve as the basis for comparison with new technologies are pulverized coal generation and FGD. Advances are being made in both, and emerging contenders for utility applications are coal gasification combined cycle, fluidized bed combustion, and others.

To date, it appears that the coal gasification combined cycle plant offers many attractive features. This technology is expensive and will be best applied when the construction is phased in over a period of time with a gas turbine added to the utility system as needed, followed by a combined cycle system as further capacity is required, and the addition of a gasifier when baseload electric utility capacity must be installed. This will permit the utility to save on construction costs by deploying only those parts of the technology actually needed at a specific time, rather than inventorying excess capacity. However, further demonstrations of the gasification combined cycle still are needed because a single commercial demonstration does not provide the engineering basis on which the entire domestic utility industry can extrapolate data.

Both the atmospheric and pressurized versions of fluidized bed technology have the potential to be more cost-effective than FGD systems. Later this month, the effectiveness of atmospheric fluidized bed technology can be evaluated at utility scale for the first time when Northern States Power returns its retrofitted Unit 2 at its Black Dog Station to service. But with the first utility-sized fluidized bed plant just beginning operation, it is unlikely that there will be sufficient data before 1990 upon which other companies can make economic decisions about the technology. Actual commercial availability will be sometime after this date. A number of tests are planned at this plant and a longer technological path must be followed before pressurized fluidized bed combustion is capable of being commercialized and widely used.

The cost of meeting the proposed SO_2 controls in S.2203 or H.R.4567 emphasizes the expected greater cost-effectiveness of clean coal technologies. Our industry does not have sufficient resources to fund both efforts simultaneously and I fear the clean coal technology program would be ended if utilities had to comply immediately with increased controls. The timetable of controls in proposed acid rain legislation is such that utilities may be able to comply with the control legislation, but at the expense of clean coal technologies which are expected to be more cost-effective and more efficient.

ECONOMIC AND ENVIRONMENTAL IMPLICATIONS

One reason our industry is so positive about clean coal technologies is that they have the potential to address one environmental issue without creating others. For example, current FGD systems often create a wet scrubber sludge that causes another environmental problem. On the other hand, a technology such as coal gasification combined cycle does not produce any extraordinary environmental problems and, in fact, may produce a useful by-product in the form of elemental sulfur. It is projected that fluidized bed technologies will also produce a dry and innocuous solid waste. Specific environmental costs must be associated with each new technology and included in assessing its potential and cost-effectiveness.

Control legislation -- as currently proposed -- creates economic penalties for industry as well as utilities. These penalties are in the form of increased capital and/or operating costs for utilities which would be passed on to customers. We believe some clean coal technologies would avoid these penalties and, thereby, improve the cost-effectiveness and efficiency of producing electricity. In turn, that should benefit all consumers -- especially those who are creating goods and services in competition with international manufacturers.

There are other implications of proposed acid rain legislation that impact the energy economy of the United States. As I mentioned previously, current technology has difficulty in meeting proposed NO_x standards. However, the gasification combined cycle technology already has proven that even high-sulfur coal from Illinois and Appalachia can be used in a manner that meets the extremely stringent air quality standards in California. Other technologies may be developed for use in states with similar stringent air quality standards. This, in turn, would enlarge the potential market for domestic coal producers and would assist an industry currently plagued by excess capacity. Clean coal technologies also would permit the utility industry a broader selection of coals, thereby creating more competition within the market. This would have the positive effect of reducing the fuel costs passed on to electricity consumers.

It also should be noted that nonproductive cost increases prompted by proposed acid rain legislation may create incentives for utilities to find new coal supplies off-shore or to import electricity from Canada.

I cannot speculate as to the impact a control program would have on life-extension efforts at various companies, but certainly a program which imposes stringent standards upon older plants may result in their premature retirement and replacement by newer, high-cost plants. The availability of clean coal technologies applicable to existing plants would help avoid the necessity for new plants.

It's clear that higher electric rates would be inevitable if Congress mandates the use of either current high-cost technology or higher cost fuel by adopting proposed acid rain legislation. This would be especially true for those utilities with older plants because the requirements of control legislation preclude the use of developing technologies to reduce emissions.

Finally, it should be pointed out that state electric utility commissions do not encourage innovative technologies that have not been commercially demonstrated because they do not meet a test of "used and useful." This was a prime motivation for our efforts in the first session of this Congress to have the Clean Coal Technology Reserve funded. We would agree with a statement submitted by Governors Earl and Sununu to the Committee on Energy and Commerce of the U.S. House of Representatives earlier this year that "Our public service commissions sometimes discourage innovation in their haste to avoid any short-term rate increases." The companies which have submitted proposals to DOE for funding from the Clean Coal Technology Reserve hope that federal funding will be the element which makes it possible for innovative technologies to be demonstrated without near-term rate increases.

SUMMARY

Clean coal technology stands at the threshold of commercial acceptance but is put at risk by any acid rain control program because of the large capital requirements to comply. My company, and I believe the utility industry at large, cannot put into place clean coal technologies and simultaneously comply with a new emission control program. The timetable for clean coal technology development is such that these technologies cannot meet the schedule proposed in acid rain control legislation. An acid rain program which constricts the coal market and choice of coals is not in the interest of industry or consumers. Nor is an acid rain program which absorbs all of the capital available for clean coal technology development and usurps the timetable for technology development in the national interest. Clean coal technologies have the potential to offer our nation increased reliance upon domestic fuels in an environmentally acceptable manner. Thus, we are seeking from the Congress strong support for an aggressive, cost-shared clean coal technology demonstration program, and we're urging continuation of extensive research into the causes and effects of acid rain. These efforts can proceed simultaneously. Together, they can ensure that this nation has the knowledge on which to base critical energy and environmental policy decisions. We appreciate the opportunity to appear before you to present our views.

Testimony of Edward L. Addison
The Southern Company
(Continued)

TABLE 1

UTILITIES INVOLVED IN CLEAN COAL SUBMITTALS TO DOE

The following electric utilities are involved in clean coal technology projects submitted to the DOE:

American Electric Power Service Corporation, Pressurized fluidized bed combustion with combined cycle

Baltimore Gas and Electric Company, Boston Edison Company, Consolidated Edison Company of New York, Inc., The Dayton Power and Light Company, and Houston Lighting & Power Company, Microbial action coal desulfurization

The Cleveland Electric Illuminating Company, Coal fired compressed air storage

Colorado-Ute Electric Association, Circulating fluidized bed combustion

Duke Power Company, New power cycle integrating coal cleaning, pulverized coal plant technology and fluidized bed technology

Electric Power Research Institute, Advanced coal cleaning

The Montana Power Company, Advanced coal cleaning and processing

Niagara-Mohawk Power Corporation, Configuration for an integrated coal gasification steam-injected gas turbine power plant

Ohio Edison Company, Advanced flue gas treatment process and Limestone injection multistage burner (LIMB) (two projects)

Orange and Rockland Utilities, Inc., Slagging combustor technology

Pennsylvania Electric Company, Integrated coal gasification combined cycle

Pennsylvania Power & Light Company and Southern California Edison Company, Package boiler cyclone coal combustor test

Southwestern Public Service Company, Circulating fluidized bed combustion

Tallahassee Electric Department, Circulating fluidized bed combustion

Tennessee Valley Authority, Lime spray dryer dry flue gas desulfurization system and Once through methanol process as an enhancement to gasification combined cycle technology (two projects)

Wisconsin Electric Power Company, Pressurized fluidized bed combustion with a turbocharger

The CHAIRMAN. Thank you.
Mr. Wootten.

STATEMENT OF JOHN M. WOOTTEN, DIRECTOR, RESEARCH AND TECHNOLOGY, PEABODY HOLDING CO., INC.

Mr. WOOTTEN. Mr. Chairman, my name is John M. Wootten. I am director of research and technology for Peabody Holding Company, the Nation's largest coal producer and the parent for Peabody Coal Co.

Peabody appears today to voice support for the technology recommendations of the United States-Canadian Special Envoy's Report on acid rain, to offer its observations on the types of proposals received by DOE under the clean coal technology solicitation, and to voice concern that acid rain will provide a strong disincentive to the use of more efficient and more environmentally acceptable clean coal technologies.

To illustrate our concern for proposed acid rain control legislation, I will share with the committee the results of Peabody's economic analysis to our recently introduced Acid Rain Control bill. The joint report on acid rain submitted by special envoys Drew Lewis and William Davis to President Reagan and Prime Minister Mulroney is equally significant in what the recommendations are as what they are not.

Mr. Lewis, in transmitting the report to the President, makes note of the serious environmental concern acid rain produces in both the United States and Canada and that the effect of the concern on diplomatic relations with Canada dictates action. In considering taking action through control of emissions, Mr. Lewis states, "The uncertain effects and high cost control dictate that we act prudently. '

Prudent action, as recommended in the report, is the implementation of a control technology commercial demonstration program. The program is to pay special interest to the removal of both SO_2 and NO_x and to those technologies that can be retrofitted through existing facilities using high sulfur coal. Nowhere in the report is there a recommendation for a multibillion-dollar-a-year sulfur dioxide emission control program as called for in many acid rain control bills.

Peabody supports the technology recommendations of the report. The numbers and types of proposals received as a result of DOE solicitation for clean coal technologies were very encouraging but raise several concerns for Peabody. The first concern is that of the 45 proposals that submitted public abstracts, only 7 can be considered retrofit technologies.

Today there is not a sufficient menu of demonstrated low cost retrofit technologies to avoid the less desirable alternatives of fuel switching and conventional flue gas desulfurization systems. What is needed are technologies that are applicable to many different types of boilers and fuel configurations in operation today at a competitive cost with fuel switching and that have emission reduction potentials from each technology or combination of technologies which address both sulfur dioxide and nitrogen oxide.

On the encouraging side is the fact that seven fluidized bed combustion system proposals and two pressurized fluidized bed system proposals were submitted.

A final concern is the potential for coal being excluded from a very attractive future utility capacity addition alternative. The Southern California Edison EPRI Coolwater project is demonstrating the commercial feasibility and desirability of integrated gasification combined cycle systems. These systems can be installed in phases. The gasification phase, which costs approximately two times the total cost of the combustion turbine and steam turbine phases will only be installed if the cost of natural gas or distillate oil relative to coal warrants the additional capital outlay.

Based on the cost of these fuels for the foreseeable future, it is quite possible that a utility may install the first phases and avoid the gasification phase; therefore, unless coal gasification costs can be reduced or coal fired gas turbines can be developed and demonstrated, coal will effectively be excluded from combined cycle applications.

This is why Peabody is supportive of clean coal technology proposals to demonstrate advanced gas combined cycle gasification and combined cycle systems and avoid coal's exclusion from fueling this technology.

There is, however, a major barrier to the development and deployment of these clean coal technologies. The private sector has already taken the initiative in its response to the clean coal technology solicitation. There is no denying the fact that concern about acid deposition and the complexity of imposing further controls were part of the impetus for the clean coal technology program.

Yet, acid rain control legislation will have the effect of precluding the use of these clean coal technologies to achieve the prescribed emission reductions. In spite of the fact that several clean coal demonstration projects are under development or actually under construction, it is unlikely that these technologies will be technologies will be sufficiently tested and proven for broad scale application in time to meet any sizable portion of the reduction requirements of the deadlines imposed.

Hence, the net effect of these bills is to deter technology development and to lock in the technologies of the 1960's, postponing the application of the more efficient technologies in the 1990's.

Not only are the debt lines in the bills too immediate to permit deployment of the new technologies, but the cost of meeting the emission reductions will absorb whatever risk capital might be available for demonstrating such technologies.

I would now like to focus the remainder of my statement on the economic and environmental impacts of legislation that require utility sulfur dioxide emission reductions in an attempt to control acid rain. I will do this by looking at H.R. 43567.

Peabody has undertaken analysis of the economic consequences of the bill, using an analytical model based on actual fuel use at individual power plants in 1984. The Peabody acid rain model is based on electric utility fuel consumption and SO_2 emissions only.

SO_2 emissions from existing powerplants would decline by 8.6 million tons annually by 1997. Of this amount, 3.8 million tons of annual SO_2 emission reduction would occur as a result of fuel switching primarily from higher sulfur coal to lower sulfur coal; 4.8 million tons of annual SO_2 emission reduction would result from the application of flue gas desulfurization units to existing powerplants.

The SO_2 reductions required by the bill fall disproportionately on Midwestern and Southern States, as shown in the attachments to my statement. The seven most heavily impacted coal producing States of Alabama, Illinois, Indiana, Kentucky, Ohio, Pennsylvania, and West Virginia must achieve a reduction of 5.3 million tons or 62 percent of the total reduction. The acid sensitive northeast States are required to achieve .3 million tons of reduction or 4 percent of the total.

The annual levelized increased cost to consumers of electricity would amount to $5.8 billion per year. Of this amount, 62 percent of the cost or $3.6 billion would occur in those seven coal-producing States most heavily impacted. Eighty percent of the cost or $4.6 billion would accrue to 11 States, adding Georgia, Michigan, Missouri, and Tennessee to the list of seven States. The acid sensitive Northeast would assume 2 percent of the cost, while the 17 Western States would pay two-tenths of 1 percent of the cost.

Some or nearly 90 million tons of annual coal production would be displaced by 1997. As a result of these coal production shifts, an estimated 78,000 jobs would be displaced in medium and high sulfur coal fields. Of this amount, 19,500 direct mining jobs would be displaced, with the remainder in the support and related job sectors.

The seven coal-producing States suffer from the dual impacts of higher utility rates and higher unemployment from coal production shifts. The seven States will experience 87 percent of the job dislocations affecting 65,000 people.

By whatever yardsticks the economic cost of H.R. 4567 are measured, it is apparent that the cost of the proposals are high. The obvious question is whether these costs will achieve the commensurate benefit.

Because current models cannot be relied on to predict spacial relationship between emissions and deposition, Peabody, with others, commissioned two studies to try to define the spacial relationship between ambient concentration of acid precursors and acid deposition. I will make a copy of those available to the committee.

These studies examine the extent of the nonlinearity in the SO_2 sulfate relationship for the 21 Northeastern States. The 21 States were divided into four regions: the West North Central; East North Central; Atlantic; and Northeast, as shown on attachment 6 of my statement.

Based on the results of the simulations, a linearity index was calculated for each region. The linearity index corresponds to the percent reduction in sulfate formed due to a reduction in ambient SO_2. For example, an index of 0.7 implies that an SO_2 reduction would be 70 percent efficient; or to say it another way, a 50 percent reduction in SO_2 would product a 35-percent reduction in sulfate.

The linearity index for wet sulfate deposition in the Northeast is 0.21 or 21 percent efficient. This means that a reduction in SO_2 concentration in the Northeast will be only 21 percent efficient in reducing wet sulfate deposition. The linearity index can be used to project the reduction in wet sulfate deposition resulting from the SO2 emission reduction required by the acid rain control legislation.

The reduction achieved in the Northeast as a result of reducing SO_2 emissions in each region that is required by H.R. 4567 as well as the cost for achieving the reduction are shown in attachment 7 to my statement. The bill would require 52 percent reduction in utility emissions in the Northeast.

Similarly, by assuming that each of the other regions plus Canada contribute equally to the SO_2 concentrations in the Northeast, then the bill would produce a 9 percent reduction in wet sulfate deposition from the utility sector. The prospect of achieving only a 9 percent reduction in wet sulfate deposition in the acid sensitive Northeast at a cost of nearly $6 billion annually constitutes an acid deposition control approach that is far from cost effective.

The recently published Acid Deposition Study of the National Research Council cited inconsistent trends between emission rates and apparent deposition rates and aquatic acidity. Moreover, the study supplied little evidence of any great danger to aquatic or terrestrial resources nor evidence of any decline in those resources as a result of acid deposition. The bottom line here is that the $6 billion spent each year is unlikely to have any effect on aquatic acidity.

Peabody supports the administration position of implementing a control technology commercial demonstration program as the prudent response to concerns over acid rain. In addition, Peabody concurs that the uncertain effects and high cost of emission control do not warrant additional controls at this time.

Moreover, utility emission control programs proposed in the acid rain control bills appear wholly inconsistent with and counterproductive to the effort to develop more efficient, less costly and less disruptive technology solutions.

We do not believe that the reductions will achieve sufficient benefits to warrant their cost. A far more prudent approach will be to use these billions of dollars to demonstrate clean coal technology so that, if necessary, existing facilities can be retrofitted or repowered. As older facilities are retired, demonstrated new technologies can be used to replace them.

Thank you.

[The prepared statement of Mr. Wootten follows:]

Statement of

John M. Wootten

Director, Research & Technology

Peabody Holding Company, Inc.

St. Louis, Missouri

Before the

Committee on Energy and Natural Resources

U.S. Senate

Washington, D.C.

June 10, 1986

Mr. Chairman, my name is John M. Wootten. I am Director of Research and Technology for Peabody Holding Company, Inc., the nation's largest coal producer and the parent of Peabody Coal Company. Peabody Holding's subsidiaries operate 41 mines in 11 states and expect to produce 65 million tons of coal during 1986. While predominately a producer of midwestern higher sulfur coal, Peabody expects this year to become the nation's largest producer of lower sulfur coal, primarily from the West and Appalachia.

Peabody appears today to voice support for the technology recommendations of the U.S.-Canadian Special Envoy's Report on acid rain, to offer its observations on the types of proposals received by DOE under the Clean Coal Technology solicitation and to voice concern that acid rain legislation will provide a strong disincentive to the use of more efficient, more environmentally acceptable clean coal technologies, many of which produce not only lower sulfur dioxide emissions but lower levels of other pollutants as well. To illustrate our concern for proposed acid rain control legislation, I will share with the Committee the results of Peabody's economic analysis of a recently-introduced acid rain control bill.

Joint Report of the Special Envoys on Acid Rain

The Joint Report on Acid Rain submitted by Special Envoys Drew Lewis and William Davis to President Reagan and Prime Minister Mulroney is equally significant in what the recommendations are as what they are not. Mr. Lewis in transmitting the report to the President makes note of the serious environmental concern acid rain produces in both the U.S. and Canada and that the effect of the concern on diplomatic relations with Canada dictates action. Although Peabody would not question the seriousness of this concern, we certainly would question whether the cause for concern is warranted by what is known about the causes and effects of acid rain. Mr. Lewis and the President, through his endorsement of the report, also recognized this uncertainty. In considering taking action through control of emissions Mr. Lewis states: ". . . the uncertain effects and high costs of control dictate that we act prudently." Prudent action as recommended in the report is the implementation of a control technology commercial demonstration program. The program is to pay special interest to the removal of both SO_2 and NO_x and to those technologies that can be retrofitted to existing facilities utilizing high-sulfur coal. Nowhere in the report is there a recommendation for a multi-billion dollar a year sulfur dioxide emission control program as called for in many of the acid rain control bills.

Peabody supports the technology recommendations of the report. We also believe that prudent action is the commercial development of more efficient and environmentally acceptable technologies for coal combustion. The Clean Coal Technology Program is just such a program and Peabody has supported and will continue to support that program. Peabody also supports the efforts of Messrs. Byrd, Regula and Rahall to appropriate the remainder of the Clean Coal Technology Fund for development of clean coal retrofit technologies.

Proposals for Clean Coal Technology Demonstrations

The number and types of proposals received as a result of the DOE's solicitation for Clean Coal Technologies were very encouraging but raise several concerns for Peabody. The first concern is that of the forty-five proposals that submitted public abstracts, only seven can be considered retrofit technologies. They were in the categories of Advanced Combusters, Sorbent Injection and Flue Gas Desulfurization and Denitrification. If at some point in the next ten years it becomes necessary to implement a utility emission reduction program, there won't be a sufficient menu of demonstrated, low-cost retrofit technologies to avoid the less desirable alternatives of fuel switching and conventional flue gas desulfurization systems. What is needed are technologies that are applicable to the many different boiler and fuel configurations in operation today, at a cost competitive with fuel switching, and have an emission reduction potential from each technology or combination of technologies which addresses both sulfur dioxide and nitrogen oxides.

On the encouraging side is the fact that seven circulating fluidized bed combustion system proposals and two pressurized fluidized bed combustion system proposals were submitted. These technologies have a very real potential for repowering of existing power plants as demonstrated by the three fluidized bed demonstration projects that are currently under construction. Peabody is providing financial support to two of these projects -- TVA and Colorado-Ute -- and has made an offer of assistance to the Northern States Power Project. It must be recognized, however, that repowering technologies which can cost between $400 and $1200 per kilowatt of installed capacity are considerably more expensive than retrofit technologies which should cost between $50 and $200 per kilowatt. Peabody has placed its support on demonstrating fluidized bed technology because we believe it will play an important role in future utility coal combustion applications.

A final concern related to the demonstration of clean coal technologies is the potential for coal being excluded from a very attractive, future utility capacity addition alternative. The Southern California Edison/EPRI Coolwater Project is demonstrating the commercial feasibility and desirability of integrated gasification combined cycle systems (GCC). It is now considered feasible to build discrete increments of capacity -- 100 to 400 MWs -- over relatively short periods of time -- 24 to 48 months -- thereby avoiding or minimizing many of the risks associated with major power plant construction in the past.* The cost of this capacity is also very attractive -- $1300 to $1400 per kilowatt.

Furthermore, GCC systems can be installed in phases. For example, an advanced combustion turbine firing natural gas or distillate oil can be installed as a first phase. A second phase could involve installing another combustion turbine. A third phase might be the addition of a steam cycle which would consist of two heat recovery boilers and a steam turbine. The utility could then install the gasification system as the fourth and final stage. Obviously, the gasification phase, which costs approximately two times the total cost of the first three phases, will only be installed if the cost of natural gas or distillate oil relative to coal warrants the additional capital outlay. Based on the cost of these fuels for

*Fluor Engineers, Inc., Planning Data Book for Gasification - Combined Cycle Plants: Phased Capacity Additions, Electric Power Research Institute, January 1986.

the foreseeable future, it is quite possible that a utility may install the first three phases and delay the gasification phase. Peabody believes that the use of natural gas or oil to generate electricity to be a mistake. Furthermore, we believe that even if the differential cost of fuel warrants installation of the gasification phase, a choice between capital outlays with the risk of uncertain recovery in a utility's rates as opposed to a pass-through fuel expense will result in the fourth phase never being installed. Therefore, unless coal gasification costs can be reduced or coal-fired gas turbines can be developed and demonstrated, coal will effectively be excluded from combined cycle applications. That is why Peabody is supportive of Clean Coal Technology proposals to demonstrate advanced GCC systems and avoid coal's exclusion from fueling this technology.

Barriers to the Development and Deployment of Clean Coal Technologies

There is, however, a major barrier to the development and deployment of these Clean Coal Technologies. Last year, Congress voted to appropriate funds for subsidizing the commercial-scale demonstration of new coal utilization technologies which are designed to be more efficient, less expensive, and more environmentally beneficial than the conventional coal-fired boiler with a flue gas desulfurization system. The Department of Energy has received proposals for 51 such clean coal demonstration projects.

Moreover, as I previously discussed, President Reagan and Canadian Prime Minister Mulroney have concluded a bilateral agreement on acid deposition which has as its cornerstone the accelerated development of clean coal technologies as the means by which emission reductions can be achieved in a cost-effective non-disruptive manner.

The private sector has already taken the initiative in this effort. The electric power industry, the coal industry and equipment suppliers have undertaken specific projects to improve the means by which we use our abundant coal resources.

There is an irony in this accelerated national, international and private sector effort to apply new technologies to the use of coal. There is no denying the fact that concern about acid deposition and the complexity of imposing further controls were part of the impetus for the clean coal technology program. Yet, acid rain control legislation will have the effect of precluding the use of these clean coal technologies to achieve the prescribed emission reductions. In spite of the fact that several clean coal demonstration projects are under development or actually under construction, it is unlikely that these technologies will be sufficiently tested and proven for broad-scale application in time to meet any sizable portion of the reduction requirements with the deadlines proposed. Hence, the net effect of these bills is to deter technology development and to "lock in" the technologies of the 1960s, postponing the application of the more efficient technologies of the 1990s and beyond. Not only are the deadlines in the bills too immediate to permit deployment of the new technologies, but the costs of meeting the emission reductions will absorb whatever risk capital might be available for demonstrating such technologies.

Economic Implications of Proposed Acid Rain Controls

I would now like to focus the remainder of my statement on the economic and environmental impacts from legislation that requires utility sulfur dioxide emission reductions in an attempt to control acid rain. I will do this by analyzing House Bill 4567, the Acid Deposition Control Act of 1986, which recently passed the House Energy and Commerce Committee's Health and the Environment Subcommittee.

Peabody has undertaken an analysis of the economic consequences of H.R. 4567 using an analytical model based on actual fuel use at individual power plants in 1984. The Peabody acid rain model is based on electric utility fuel consumption and SO_2 emissions only. The quantity and quality of the fuel is based upon 1984 purchases as reported on FERC Form 423 reports. The cost of fuel is based upon 1984 from the same source. SO_2 emissions were derived from consumption data gathered on EIA Form 759 for 1984. In keeping with the utility nature of the model, SO_2 emissions from new plants coming on line during the time period covered by the legislation are also projected so that any required offsets can be calculated.

The allocation of reductions in SO_2 emissions to each state is done in direct accordance with the legislation. The model assumes an enforcement mechanism based on an "Allowable Emission Rate" or AER for each state. Legislation, such as H.R. 4567 and S. 2203, sets an AER for each state. The model then allows each utility to achieve the reduction on a system basis in the most cost effective manner. As few as one or as many as all plants in a system with emissions over the AER may be required to reduce emissions. That is, intra-utility system trading among sources operating above the AER is permitted, but not inter-system or inter-state trading.

The cost and quality of replacement fuel that might be selected by a utility to achieve the required reduction is calculated from the same FERC Form 423 used for calculating existing emissions and fuel costs. This "compliance" fuel, its characteristics and cost in each state is generated from shipments entering the state or an adjacent state which were below the AER during 1984. The cost of compliance fuel is increased by a demand push which is bounded by the implied cost of the other main compliance strategy; namely, installing and operating flue gas desulfurization equipment at each plant and continuing to use high-sulfur coal. A 20 percent cost increase is used.

Flue gas desulfurization (scrubbing) costs are developed utilizing TVA* projections for capital and O&M. Scrubber capital costs are increased by 30 percent to account for retrofitting the generating plant. Scrubbers are assumed to achieve a 90 percent SO_2 removal efficiency for all applications.

After an economic decision regarding the most cost effective compliance strategy has been made at each plant, the coal that is displaced is summed for each consuming state. This total displacement is then allocated to producing states according to the percentage each producing state contributed to the total of all such shipments in 1984.

The average mine productivity in each producing state is divided into the tons displaced to estimate the number of miners expected to lose their jobs because of coal displacement. To estimate total job

*Tennessee Valley Authority, Economic Evaluation of Limestone and Lime Desulfurization Processes, prepared for EPA (March 1983).

impacts, the model uses a previously developed Department of Commerce multiplier of three support jobs for each direct mining job lost.

Based on the stationary source provisions of H.R. 4567 which are shown in Attachment 1, each state would have to achieve a 2.0 lbs. of SO_2 per million Btu by 1993 and 1.2 lbs. by 1997. In 1984, 16 states had state average emission rates greater than 2.0 lbs./MM Btu (see Attachment 2). Only one state in the acid sensitive Northeast region, New Hampshire, would be required to take action in the first phase.

In the second phase, 24 states would be required to make reductions. Three states in the acid sensitive Northeast will be impacted -- New Hampshire, Massachusetts and New York.

SO_2 emissions from existing power plants would decline by 8.6 million tons annually by 1997. Of this amount, 3.8 million tons of annual SO_2 emission reductions would occur as a result of fuel switching, primarily from higher sulfur coal to lower sulfur coal. 4.8 million tons of annual SO_2 emission reductions would result from the application of flue gas desulfurization units to existing power plants.

The SO_2 reductions required by the bill fall disproportionately on midwestern and southern states as shown in Attachment 3. The seven most heavily impacted coal producing states of Alabama, Illinois, Indiana, Kentucky, Ohio, Pennsylvania and West Virginia must achieve a reduction of 5.3 million tons or 62 percent of the total. The acid sensitive Northeast states are required to achieve a reduction of 0.3 million tons or 4 percent of the total.

The annual levelized increased cost to consumers of electricity would amount to $5.8 billion per year. Of this amount, 62 percent of the cost, or $3.6 billion, would occur in those seven coal producing states most heavily impacted as shown in Attachment 4. Eighty percent of the cost, or $4.6 billion, would accrue to eleven states, adding Georgia, Michigan, Missouri and Tennessee to the list of seven states. The acid sensitive northeastern states would assume 2 percent of the cost ($139 million), while the 17 western states would pay only two-tenths of one percent of the cost ($14 million).

Some 89.7 million tons of annual coal production would be displaced by 1997. As a result of these coal production shifts, an estimated 78,000 jobs would be displaced in medium and high-sulfur coalfields; of this amount, 19,500 direct mining jobs would be displaced, with the remainder in the support and related job sectors.

As shown in Attachment 5, the seven coal producing states suffer from the dual impacts of higher utility rates and higher unemployment from coal production shifts. The seven states will experience 87 percent of the job dislocations affecting 65,000 people.

One might argue that some of these states -- Alabama, east Kentucky, Virginia and West Virginia -- will have net increases in jobs due to their low-sulfur coal production capabilities. This probably will occur; however, it does not lessen the human impact. For example, miners are unlikely to move their families from western Kentucky to eastern Kentucky, and as a result, the communities where the job dislocations occur will experience the unemployment and the economic woes associated with the shutdown of an area's major employer.

In the short term, there will be an increase in demand for low-sulfur coal causing the price to increase, but in the long run, acid rain control legislation will work to the detriment of the coal industry. Rising demand and rising prices will make imported coal more competitive. Utilities will be encouraged to utilize or build alternative forms of energy -- nuclear, oil and gas. Moreover, as we have seen in the last 13 years, as the price of electricity increases the demand decreases.

Based on this analysis, Peabody believes that acid rain control legislation, and more specifically H.R. 4567, will disproportionately increase electrical rates in the Midwest and South and create significant mining job dislocations in high-sulfur coal producing states. In the long run, the legislation will produce detrimental results for the entire coal industry.

Environmental Implications of Proposed Acid Rain Controls

By whatever yardsticks the economic costs of H.R. 4567 are measured -- whether those developed by OTA, EPA, the Edison Electric Institute, or even Peabody -- it is apparent that the costs of this proposal are high -- in consumer electric bills, in job losses and in human suffering and in higher domestic production costs which further erodes the competitive viability of our products in the world marketplace. The obvious question is whether these costs will achieve a commensurate benefit.

Peabody has long been concerned with the effectiveness of acid deposition control bills which attempt to reduce acid deposition by implementing emission controls among the states on a disproportionate basis. The scientists who authored the National Research Council's June 1983 report on acid deposition articulated their inability to "objectively predict the consequences for deposition in ecologically sensitive areas of the changing spatial pattern of emissions in eastern North America, such as by reducing emissions in one area by a larger percentage than in other areas." H.R. 4567 certainly adopts this unpredictable approach.

Because current models cannot be relied upon to predict spatial relationship between emissions and deposition, Peabody, in conjunction with Consolidation Coal Company and Amax Coal Company, commissioned two studies by Systems Applications, Inc., a California firm specializing in environmental analysis, to try to define the spatial relationship between ambient concentrations of acid deposition precursors and acid deposition. The studies were an attempt to supplement the findings of the National Research Council and specifically to approximate the decrease in acid deposition that can be expected in a receptor area as a result of a reduction in precursor concentrations.

The first study completed in January 1984 presented the results of simulations of the atmospheric chemistry of sulfate and nitrate formation performed to investigate the effect of changes in SO_2, NO_x and reactive hydrocarbon concentrations for conditions typical of midwestern and northeastern America. The model calculations suggested that the relationship between sulfate and SO_2 is nearly linear in a cloud-free atmosphere, but is strongly non-linear when processes such as wet deposition occur.

The second study completed in February 1986 examined the extent of the nonlinearity in the SO_2/sulfate relationship for the 21 northeastern states. The chemistry of sulfate formation is sensitive to such factors as the ambient concentration of SO_2, NO_x and oxidants, time of day, geographic location, season of the year and the occurrence of clouds and rain. All these factors were considered in the model simulations. The 21 states were divided into four regions -- West North Central, East North Central, Atlantic and Northeast as shown in Attachment 6.

Based on the results of the simulations, a linearity index was calculated for each region. The linearity index corresponds to the percent reduction in sulfate formed due to a reduction in ambient SO_2. For example, an index value of 0.7 implies that an SO_2 reduction would be only 70 percent efficient, or to say that another way, a 50 percent reduction in SO_2 would produce a 35 percent reduction in sulfate. The linearity index for wet sulfate deposition in the Northeast is 0.21. This means that a reduction in SO_2 concentration in the Northeast will be only 21 percent efficient in reducing wet sulfate deposition. The linearity index can be used to project the reduction in wet sulfate deposition resulting from the SO_2 emission reduction required by acid rain control legislation.

Attachment 7 summarizes the reduction achieved in the Northeast as a result of reducing SO_2 emissions in each region as required by H.R. 4567, as well as the cost for achieving the reduction. H.R. 4567 would require a 52 percent reduction in utility SO_2 emissions from the northeast region. During 1980, utility emissions in the Northeast represented 10 percent of the total SO_2 emissions and, therefore, it is assumed that utility emissions represent 10 percent of the ambient concentration. Studies have shown that while local emissions are the dominant source of local ambient concentrations, a portion of the concentrations of SO_2 in the Northeast can reasonably be attributed to sources outside the region. An estimate on the high side would be that 50 percent of the concentrations would be attributed to local sources in the region and that 50 percent is transported into the Northeast from the Atlantic, East North Central, West North Central regions and Canada.

As a result, utility emissions, which are 10 percent of the 50 percent contributed by all sources in the Northeast, would represent 5 percent of the total ambient concentration. If northeastern utility SO_2 emissions are reduced by 52 percent, a total SO_2 reduction of 2.5 percent would occur. If a reduction in emissions produces an equal reduction in ambient SO_2 concentration, H.R. 4567 would have produced a 0.5 percent reduction in wet sulfate deposition from the utilities in the northeast region. Furthermore, by assuming that each of the other regions contributes equally to the SO_2 concentrations in the Northeast, then H.R. 4567 would produce a 9 percent reduction in wet sulfate deposition from the utility sector.

The prospect of achieving only a 9 percent reduction in wet sulfate deposition in the acid-sensitive Northeast at a cost of nearly $6 billion annually constitutes an acid deposition control approach that is far from cost effective. The recently published acid deposition study of the National Research Council, an affiliate of the National Academy of Sciences, indicated that while there is an apparent linkage between emission rates and deposition rates over wide geographic areas, the actual effects of deposition appear to be sensitive to such variables as weather, soil content, vegetation, and underlying geology. The study cited inconsistent trends between emission rates, apparent deposition rates, and aquatic acidity. Moreover, the study supplied little evidence of any widespread danger to aquatic or terrestrial resources nor evidence of imminent decline in those resources as a result of acid deposition. The bottom line here is that this $6 billion spent each year is unlikely to have any effect on aquatic acidity.

Summary

Peabody supports the Administration's position of implementing a control technology commercial demonstration program as the prudent response to concerns over acid rain. In addition, Peabody concurs that the uncertain effects and high cost of emission control do not warrant additional controls at this time. Moreover, utility emission control programs proposed in acid rain control bills appear wholly inconsistent with and counterproductive to the effort to develop more efficient, less costly, and less disruptive technolgical solutions. We do not believe that the reductions will achieve sufficient benefits to warrant their costs. A far more prudent approach will be to use these billions of dollars to demonstrate clean coal technologies so that, if necessary, existing facilities can be retrofitted or repowered and as older facilities are retired, demonstrated new technologies can be used to replace them.

Attachment 1

Provisions of H.R. 4567
Acid Deposition Control Act of 1986
for Stationary Sources

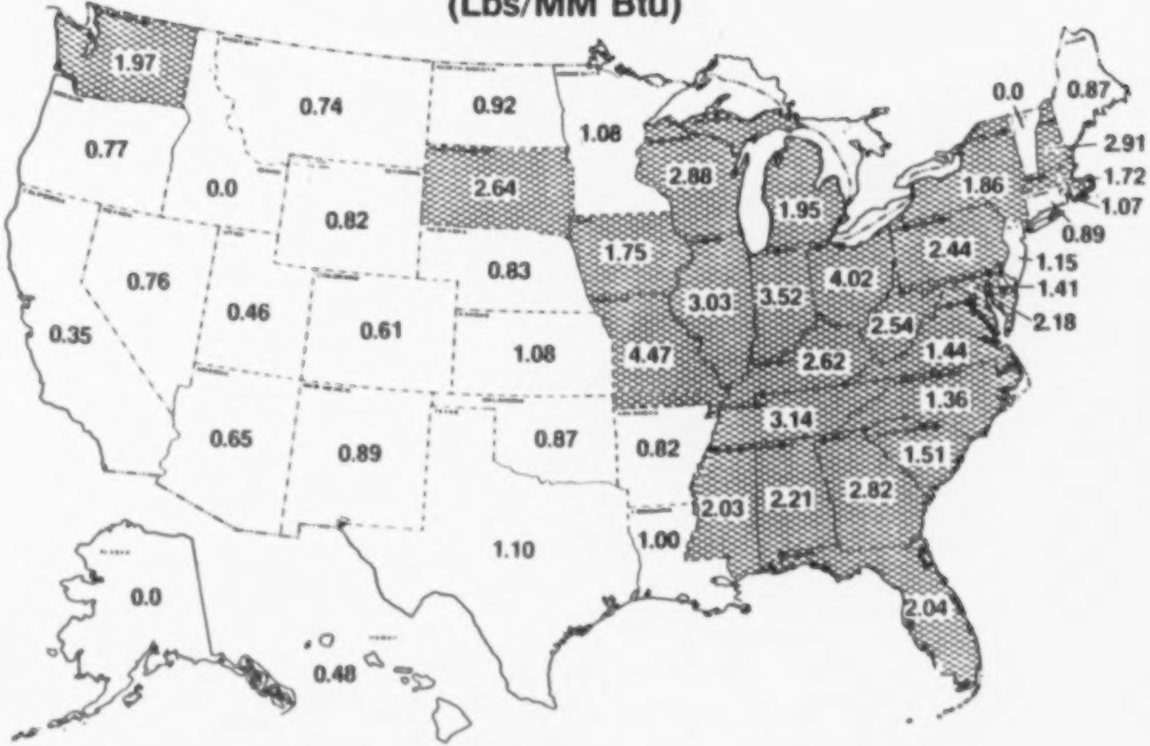
UTILITY: (Statewide Monthly Average)
  SO_2 Emissions – Achieve 2.0 lbs. SO_2/MM Btu -- 1993
  -- Achieve 1.2 lbs. SO_2/MM Btu -- 1997
  NO_X Emissions – Achieve 0.6 lbs. NO_X/MM Btu – 1997

INDUSTRY: (Statewide Monthly Average)
  SO_2 Emissions – Achieve 1.2 lbs. SO_2/MM Btu – 1997
  NO_X Emissions -- Achieve 0.6 lbs. NO_X/MM Btu – 1997

INDUSTRIAL PROCESSES:
  SO_2 Emission – Reduce to Economically and Technically Achievable Levels – 1997
  NO_X Emission -- Reduce to Economically and Technically Achievable Levels – 1997

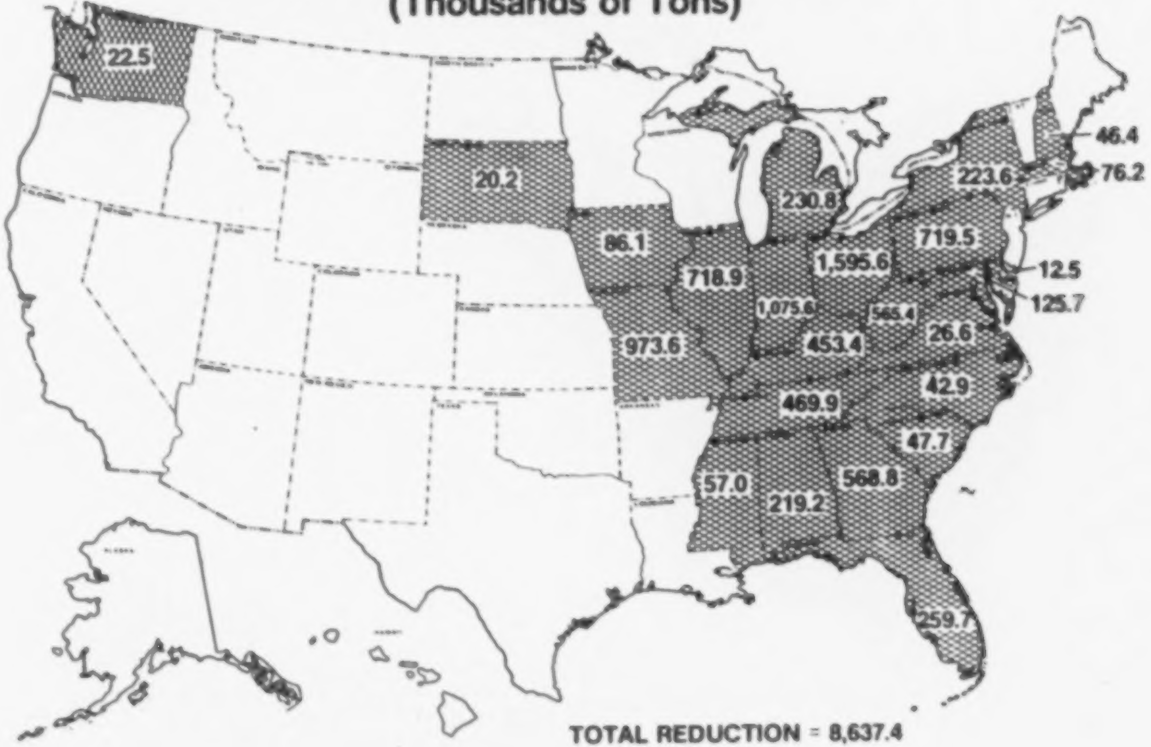
Attachment 2

1984 Average State Utility SO$_2$ Emission Rates (Lbs/MM Btu)



Attachment 3

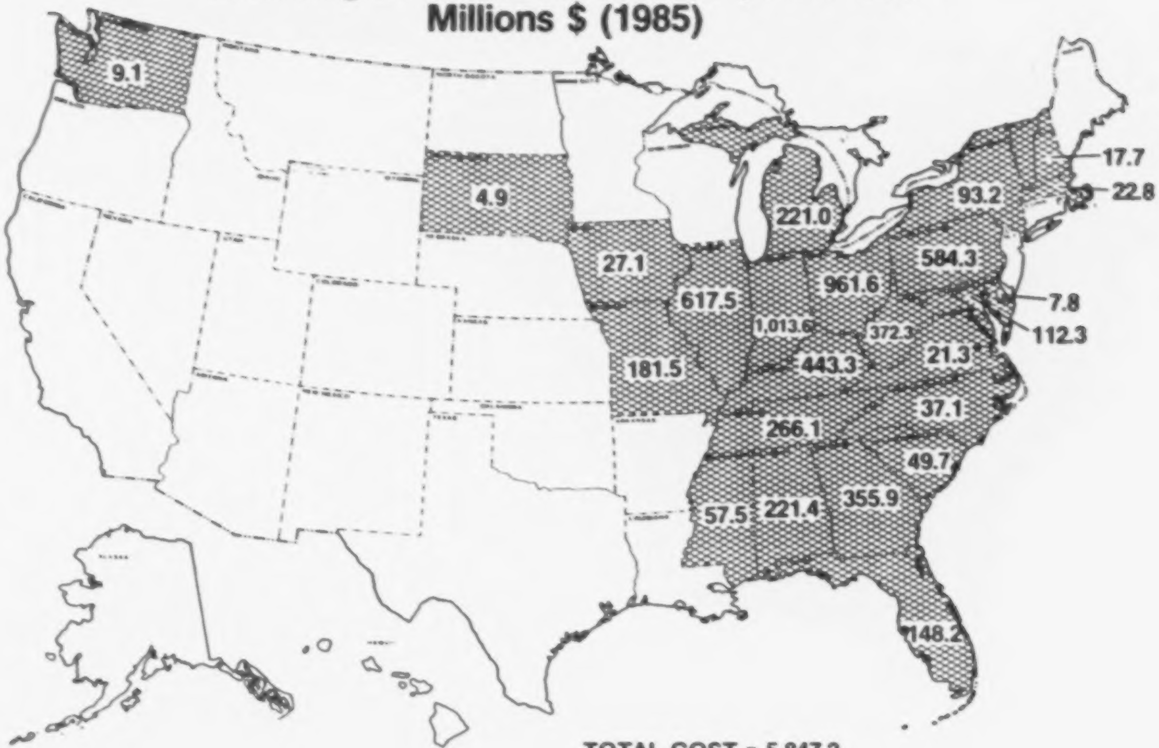
Utility SO₂ Emission Reductions Required by the Waxman Bill, H.R. 4567 (Thousands of Tons)



TOTAL REDUCTION = 8,637.4

Attachment 4

Levelized Annual Electric Cost Increases Resulting from the Waxman Bill, H.R. 4567 Millions $ (1985)



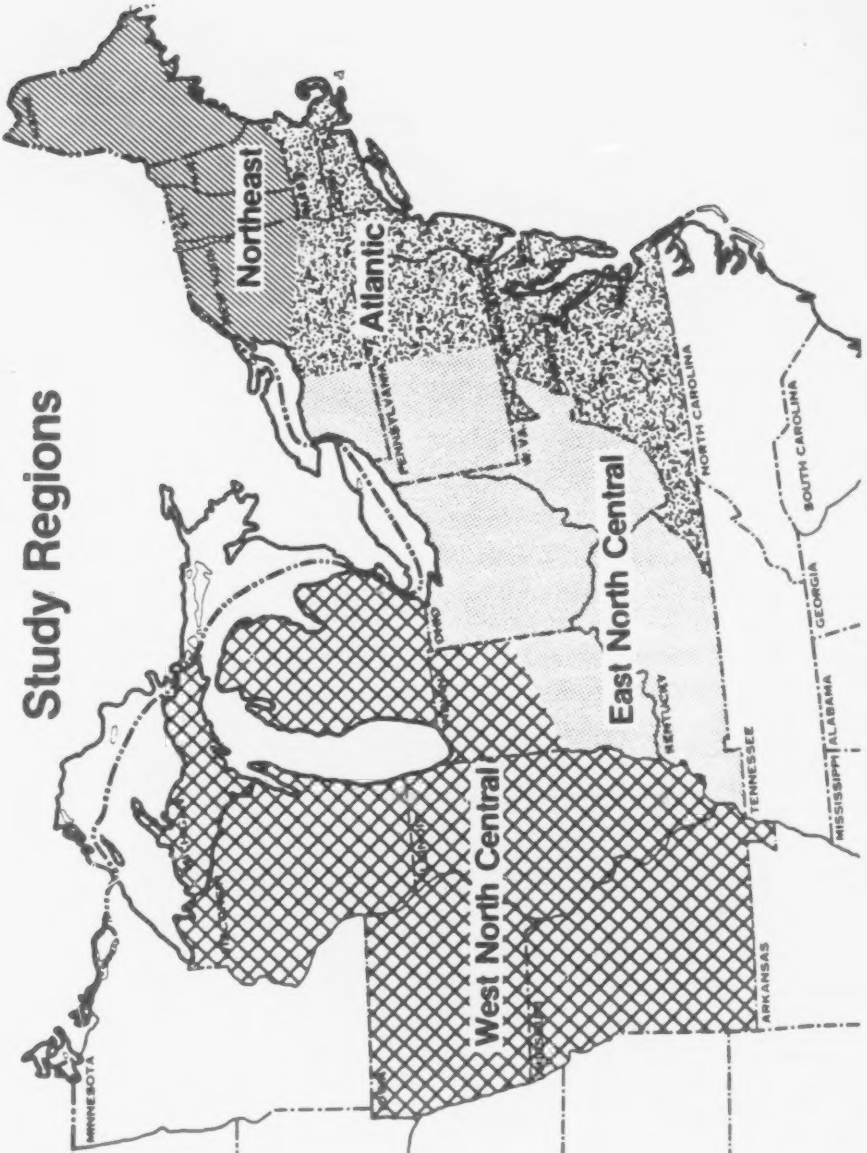
TOTAL COST = 5,847.2

Attachment 5

Impacts of H.R. 4567 on Seven Coal Producing States

	Required Utility SO_2 Reduction (%)	Levelized Annual Increase in Electrical Costs (Million $)	Total Tons of Coal Displaced (000 Tons)	Direct Mining Job Dislocations	Total Job Dislocations
Alabama	51	221.4	1,953	537	2,146
Illinois	74	617.5	18,881	4,081	16,321
Indiana	70	1,013.6	4,574	776	3,103
Kentucky	59	443.3	21,760	4,263	17,050
Ohio	71	961.6	13,349	3,089	12,354
Pennsylvania	57	584.3	9,158	2,431	9,725
West Virginia	61	372.3	8,259	2,001	8,005
Total U.S.	61	5,847.2	89,709	19,509	78,035

Attachment 6



Attachment 7

Estimate of the Percent Reduction in Wet Sulfate Deposition in the Northeast Resulting from Enactment of H.R. 4567

	Contribution to the SO_2 Concentration in the Northeast	1980 Utility SO_2 Emission as a Percent of Total SO_2 Emissions	Utility SO_2 Emission Reduction Required by H.R. 4567	Linearity Factor	Reduction in Wet Sulfate Deposition	Annual Increase in Electric Cost
	(%)	(%)	(%)		(%)	(MM 1985 $)
Northeast (NY, Adirondacks, VT, NH & ME)	50.0	10	52	0.21	0.5	17.7
Atlantic (MA, CT, RI, S.E. NY, E. PA, NJ, MD, DE & VA)	12.5	63	38	0.58	1.7	503.0
East North Central (W. NY, W. PA, WV, OH, KY, S. IN)	12.5	81	62	0.56	3.5	2,622.8
West North Central (N. IN, MI, IL, MO, IA & WI)	12.5	77	62	0.55	3.3	1,553.9
Canada	12.5	—	0	—	—	—
Total	100.0				9.0	5,847.2*

*Represents total U.S. cost of H.R. 4567

The CHAIRMAN. Thank you.
Mr. High.

STATEMENT OF MICHAEL D. HIGH, DIRECTOR, DIVISION OF ENERGY DEMONSTRATIONS AND TECHNOLOGY, TENNESSEE VALLEY AUTHORITY

Mr. HIGH. Thank you, Mr. Chairman. I am Michael High, Director of the Division of Energy, Demonstrations and Technology for the Tennessee Valley Authority. I am pleased to be here today to respond to your invitation to present information on TVA's research and demonstration activities and their relationships to the Department of Energy's Clean Coal Technology Program and proposed strategies for control of acid rain.

As one of the Nation's largest producers of electricity, TVA has experienced firsthand knowledge in solving interrelated energy and environmental problems in three areas which I think should be of interest to this committee.

TVA has reduced the annual SO_2 emissions from our coal fired plants by about 1 million tons since 1977 and has considerable knowledge about the problems and the costs associated with implementation of emission control technologies.

For the past 15 years, TVA has operated one of the most comprehensive research and development R&D facilities in the Nation, controlling SO_2 emissions from high sulfur coal, and understands the risk and need for deployment of lower cost control technology or large fossil fuel-fired boilers.

Since TVA has the responsibility for planning new and replacement generating capacity that can meet clean air standards, we continually investigate and monitor emerging coal technologies for future use on our system.

In the 1960's, TVA embarked on a $100 million program to install precipitators on all of our coal fired plants by 1975. During this time the Clean Air Act Amendments were passed in 1970, and by 1977 TVA was involved in probably the largest emission reduction program in the Nation.

Three control strategies were implemented for reducing SO_2 emissions: burning low sulfur coal, which you have heard referred today as fuel switching; installing plants for washing the coal before combustion—we currently wash about 85 percent of the coal we burn or have washed; and installing wet limestone fuel gas desulfurization facilities, or FGD.

Of the majority of TVA plants, the implemented strategy was fuel switching; however, two major coal-burning plants were constructed for coal supplies, and FGD processes were installed at two sites, our Paradise units one and two and at Widows Creek, for a total capacity of 400 megawatts.

In recent years, studies by TVA have indicated that more flexible mix of technology options may be needed to be available in the future. For situations involving medium sulfur coal and moderate levels of SO_2 removal, a spray dryer FTG process may provide a simpler, less costly option than the wet limestone FGD.

For a new plant design and for certain major retrofit and repowering applications, the atmospheric fluid bed combustion, AFBC, compares favorably with conventional coal fired boilers. Because of this, we have recently geared our research and development and demonstration activities to this spray dryer technology and have pursued the AFBC technology vigorously since about 1979.

One point of emphasis pertinent to these proceedings, I believe, is TVA's extensive experience in development programs. Over the years, TVA has been one of the most active organizations in evaluating and developing potential processes for control of SO_2 and flue gas. This work has followed a logical sequence, ranging from technical and economic assessments of both new and existing technologies to bench-scale and small pilot plant studies to prototype units and finally to demonstration and commercial units.

Many of the early FGD systems installed in the United States including the unit at our Widows Creek 8 plant, were designed based on information generated at our Shawnee pilot plant research facility.

Since 1982, TVA has redirected its SO_2 R&D activities from wet processes to dry flue gas desulfurization processes, or DFGD. DFGD processes basically employ the lime spray dryer followed by a fabric filter or an electrostatic precipitator. The lime spray dryer process has potential to have several advantages over the wet limestone FGD. Unfortunately, this technology has not been demonstrated sufficiently on utility boilers burning high sulfur coal and have only been used in low sulfur applications.

In the higher sulfur coal applications, burning will require SO_2 removal and particulate collection efficiencies much higher than low sulfur coal applications.

In 1982, TVA entered into agreements with two major suppliers of spray dryer technology to test their processes with a fabric filter. These one-to two-megawatt spray dryer/fabric filter pilot plants were located at our Shawnee research facility and took combustion gases from a unit burning high sulfur western Kentucky coal. The results of these pilot studies encouraged us and suggested that the lime base spray dryer followed by a fabric filer could be applicable to medium and high sulfur eastern coals.

The next two steps which are pertinent to these hearings, I believe, are to demonstrate the operation and reliability of a full-scale lime spray dryer followed by a fabric filter over a full range of operating conditions of a utility boiler and to obtain large-scale data with electrostatic precipitator.

To take one of these steps, TVA and the General Electric Company has proposed a 24-month demonstration project in response to DOE's Clean Coal Technology Program. This demonstration facility would be built at our TVA Shawnee steamplant and would cost about $35.5 million. TVA and General Electric are prepared to invest half of that amount and request the additional funding from DOE's Clean Coal Technology Program. Engineering and construction of that facility could begin as soon as those funds are committed.

TVA began the second step of this process early in 1985 when we initiated tests of a 1-megawatt scale on a lime spray dryer with an ESP. In order to examine the ability to scale this one megawatt data to full-scale retrofit system, TVA began in the fall of 1985 to design and construct a 10-megawatt dry flue gas desulfurization with an ESP, or electrostatic precipitator. This 10-megawatt system has a precipitator similar to those at TVA's large steamplants which is pertinent to retrofit applications.

This project is funded principally by TVA with financial assistance from the Electric Power Research Institute and Ontario Hydro of Canada. Startup of that facility is scheduled for the fall of 1986. TVA has committed approximately $20 million to this project thus far.

Now, let me discuss an emerging technology that you have heard about so much this morning that permits sulfur removal during the combustion process, and that is fluidized bed combustion. The AFBC technology has made significant advances in acceptance by utilities by virtue of its successful development progress at the TVA 20-megawatt pilot plant and by virtue of successful operations of industrial sized units.

The important shortcoming is that it has not been built to produce electric power on a scale attractive to utilities. This situation should be rectified within the next 2 to 2½ years. Utilities, with full funding from the Electric Power Research Institute, are building and beginning to operate three utility-sized demonstration units within the next 2 years.

TVA is repowering a 160 megawatt unit at Shawnee with a new AFBC boiler. Northern States Power Co. is converting a boiler at the Black Dog Plant in Minnesota, and Colorado-Ute is uprating a unit at the Nucla Station. Three utilities have announced intentions to buy commercial units. Montana-Dakota Utilities plans to retrofit an 80 megawatt boiler at the Haskett Station. Texas-New Mexico Power is planning a plant to produce 150 megawatts. Recently, Wisconsin Electric Power announced plans to convert four units totaling 500 megawatts to AFBC. These demonstrations and commercial plants should demonstrate the feasibility of the AFBC option.

Now, let me take 2 minutes to address the relationship of these two particular technologies I have discussed to the Clean Coal Technology Program of the DOE. First, let me point out that it takes anywhere from 7 to 20 years to develop a new process that the electric utility industry is willing to risk on their operating plants.

This is particularly true where large units are involved and usually takes several years of successful operation in smaller sizes, but on utility boilers, for them to take these risks. Several FDG systems are at the stage of their operation where they are small but full-scale utility boilers are needed; that is, demonstrations. The ability of these technologies to help in the time frame of most proposed Clean Air Act Amendments depends critically on moving forward with them.

The DOE Program can benefit these directly, but any delay will produce a corresponding one delay in that technology's potential to contribute to cleaner coal combustion. The spray dryer FDG is in that category along with several others that have gone through the bench-scale pilot plant into prototype scale over the last 7 to 10 years. Even with a successful demonstration period of, say, 18 months to 2 years, the earliest deployment for retrofit would probably be mid-1990 to mid-1992.

The AFBC technology, on the other hand, does not depend on the DOE Clean Coal Technology Program for early deployment. Based on current efforts of repowering, AFBC could begin in the 1990 to 1991 timeframe, making decisions based on the state of knowledge today and boiler retrofits in the 1989 to 1990 timeframe. New grassroots plants will probably not be ready before 1994.

In summary, Mr. Chairman, TVA believes that this committee's efforts to examine the relationship between the DOE's Clean Coal Technology Program and the proposed strategies for the control of acid rain is important. It is imperative that funds be allocated to those processes not yet fully developed that could produce cost over present available technology.

On the other hand, risky technologies, while maybe appearing to provide some economic promise for the future, should be viewed very cautiously as reliable strategies for the control of acid rain.

TVA's plans for developing both the spray dryer and the AFBC technology is based upon sound engineering design and developmental programs. Congress, through DOE, is now providing $30 million to our 160 megawatt demonstration. We strongly believe that a national commitment to further develop these technologies is highly desirable.

I thank you very much for the opportunity to address this committee.

[The prepared statement of Mr. High follows:]

STATEMENT OF MICHAEL D. HIGH
DIRECTOR
DIVISION OF ENERGY DEMONSTRATIONS AND TECHNOLOGY
TENNESSEE VALLEY AUTHORITY
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
JUNE 10, 1986

I am pleased to be here today in response to your invitation to present information on TVA's research and demonstration activities and their relationship to the Department of Energy's Clean Coal Technology program and the proposed strategies for the control of acid rain.

As one of the Nation's largest producers of electricity, as well as a Federal instrumentality providing for the stewardship of the Tennessee Valley region's natural resources, TVA has experience that should be of interest to this committee and to Congress. As a result of this experience in solving interrelated energy and environmental problems, TVA has firsthand knowledge in three areas which are highly relevant to this committee's interest:

- Having reduced the annual sulfur dioxide emissions from TVA coal-fired generating plants by about a million tons since 1977, TVA has considerable knowledge about the problems and the cost of pollution control technology.

- Having operated over the past 15 years one of the most comprehensive research and development (R&D) facilities in the Nation for controlling

SO_2 emissions from high-sulfur coal, TVA understands the risks of and need for deployment of new lower cost control technology for large fossil fuel-fired boilers.

- Having responsibility for planning new and replacement generating capacity, TVA continually investigates and monitors emerging coal-burning technologies for future use on the TVA system.

TVA's Air Pollution Control Program

In the 1960s, TVA embarked on a $100 million program to install precipitators on all of its coal-fired units by 1975. While this program was in progress, the Clean Air Act Amendments of 1970 were passed. TVA greatly expanded its control program as a result of the 1970 amendments and by 1977 was involved in the largest emission reduction program in the Nation.

Table I shows the 1977 and the 1983 SO_2 emission levels for each TVA coal-fired plant. Table II shows the major control strategies implemented the capital expenditures, and the approximate annual compliance cost in 1984. The capital expenditures through 1984 for pollution control equipment of $1,285 million are equivalent to $73/kW, a significant increase from the $6/kW invested by TVA through the early 1970s. The $389 million for annual costs in 1984 to TVA represents an increase in revenue requirements of about 9.5 percent. The reduction of one million tons in SO_2 emissions represents a 6-percent reduction in overall SO_2 emissions from all utility sources in the United States.

As indicated in table II, three control strategies were implemented by TVA for reducing total SO_2 emissions: burning a lower sulfur coal, installing plants for washing the coal before combustion, and installing limestone flue gas desulfurization (FGD) facilities. At the majority of TVA plants, the implemented strategies involved switching to a lower sulfur coal; however, two major coal-cleaning plants were constructed for Cumberland and Paradise coal supplies. FGD processes were installed on four units at two sites: Widows Creek units 7 and 8 and Paradise units 1 and 2.

Recent economic studies by TVA indicate that a better mix of technology options may be available in the future. For cases involving medium-sulfur coal and moderate levels in SO_2 removal, a spray dryer FGD process may provide a simpler, less costly option than limestone FGD. For a new plant design and in certain major retrofit applications, atmospheric fluidized bed combustion (AFBC) compares favorably with conventional coal-fired boilers with limestone FGD. Because of this, we have recently geared our research, development, and demonstration activities to the spray dryer and AFBC technologies. These technologies are discussed in more detail in the following sections.

SO2 Control R&D Facility

Over the years, TVA has been one of the most active organizations in evaluating and developing potential processes for the control of SO_2 in flue gas. This work has followed a logical sequence ranging from technical and economic assessments of both new and existing technologies to bench-scale and small pilot plant studies, to prototype units, and finally to demonstration and commercial units. Many of the earlier FGD systems installed in the United States, including our Widows Creek unit 8 FGD system, were designed based on information generated at TVA's Shawnee pilot and prototype SO_2 control R&D facility.

Since 1982, TVA has redirected it's SO_2 R&D activities from wet processes (limestone FGD) to dry flue gas desulphurization processes (DFGD). DFGD processes basically employ the use of a lime spray dryer followed by a fabric filter or an electrostatic precipitator. The lime spray dryer process has numerous projected advantages over wet limestone FGD. These include: (1) lower installed cost per kilowatt, (2) lower maintenance costs, and (3) lower power consumption. Unfortunately, the spray dryer has only been demonstrated sufficiently on utility boilers burning low-sulfur coal where there is little need for additional SO_2 removal in the particulate collection device (baghouse). The higher sulfur coal burning will require SO_2 removal in the particulate collection device to achieve high-SO_2 removal efficiencies for the system.

In 1982, TVA entered into agreements with two major suppliers of spray dryer technology to test their processes with a fabric filter. These 1- to 2-MW spray dryer/fabric filter pilot plants were located at TVA's scrubber R&D facility at Shawnee and took gas from a unit burning high-sulfur coal. The results of these pilot studies were encouraging and suggest that the lime-based spray dryer followed by a fabric filter could be applicable to medium- and high-sulfur eastern U.S. coals

The next step would be to demonstrate the operation and reliability of a full-scale lime spray dryer followed by a fabric filter over the full range of operating conditions of a utility boiler. To accelerate this development, TVA has proposed a 24-month demonstration in response to DOE's Clean Coal Technology program solicitation. The demonstration facility would be built at TVA's Shawnee Steam Plant and would cost approximately $35.50 million to design, construct, and operate throughout the duration of the demonstration program. TVA and General Electric Company are preparing to invest $17.75 million and are requesting that DOE provide additional funding of $17.75 million under the Clean Coal Technology program.

As a further commitment, TVA initiated tests in early 1985 at the 1-MW level on a lime spray dryer followed by an electrostatic precipitator. Data generated during the summer of 1985 suggest that a lime spray dryer followed by a precipitator may be a viable option for retrofit technology on TVA coal-fired power plants in the future. In order to examine the ability to scaleup the 1-MW data to full-scale retrofit systems, TVA began in the fall of 1985 to design and construct a 10-MW spray dryer followed by a precipitator. This 10-MW system will have a precipitator similar to those at TVA's large steam plants. This project is funded principally by TVA with financial assistance from the Electric Power Research Institute (EPRI) and Ontario Hydro of Canada. Startup of this facility is scheduled for the fall of 1986, and pertinent data for full-scale demonstrations should be available by early 1988. Approximately $20 million will be spent on this project.

Emerging Coal-Burning Technologies

AFBC is an advanced coal-burning process which provides a method of burning coal economically and in an environmentally acceptable manner. In the fluidized bed combustion process, air and combustion gases are passed through a bed of coal, ash, and sorbent particles. The gas velocity is sufficient to suspend the small particles and create a turbulent mixture which resembles a liquid that is termed "fluidized bed." When the process takes place at near atmospheric pressure, it is termed "atmospheric fluidized bed combustion."

In the typical AFBC boiler, coal is fed into the bed and burns while mixing with the bed's hot particles. Thermal energy is removed by heat transfer to water in boiler tubes, and the resultant steam is used to drive a turbine. This method of coal firing has several advantages. Most coals contain sulfur; so a chemically active sorbent, such as limestone, is fed to the bed and reacts with the sulfur before it escapes from the combustion process. This capability to capture sulfur in situ eliminates the need for expensive add-on sulfur removal systems and makes AFBC boilers very attractive to utilities. Furthermore, the optimum temperature for the sulfur capture reaction is approximately 1,550°F which is low enough to inhibit NO_x formation, reduce operation and maintenance problems associated with ash fusion, and permit a wide range of fuels to be burned without fouling. Because of the excellent mixing in the turbulent bed, granular coal and sorbent particles are used instead of pulverizing the coal. Heat transfer coefficients within the bubbling bed are about four times greater than in convection pass units; therefore, costly tube surface requirements are reduced. The solid waste is dry and can be disposed of either as conventional waste or utilized in commercial applications.

TVA's interest in AFBC began in 1976 when it commissioned three of the leading boilermakers to prepare conceptual designs for a 200-MW demonstration plant. The information developed indicated that too many uncertainties existed to proceed. To resolve the technical uncertainties, TVA took a major step in utility development by constructing a 20-MW AFBC pilot plant at the Shawnee Steam Plant in Paducah, Kentucky. This unit was started up in 1982 and has been tested over 15,000 hours in an EPRI/TVA program to provide data on critical design, performance, and operating issues.

AFBC technology has made significant advances in acceptance by utilities by virtue of its successful developmental progress at pilot and industrial plants. An important shortcoming is that it has not been built to produce electric power on a scale attractive to utilities.

Utilities, with cofunding from EPRI, are building and will operate three utility-size demonstration units. TVA is repowering a 160-MW unit at Shawnee with a new AFBC boiler. Northern States Power is converting a boiler at the Black Dog Plant in Minnesota to bring its capacity to 125 MW. Colorado-Ute is uprating a unit at the Nucla Station in Colorado by adding a new 110-MW AFBC boiler. Three utilities have committed to commercial units. Montana-Dakota Utilities is converting an 80-MW boiler at the Haskett Station. Texas-New Mexico Power is building a new plant to produce 150 MW. Wisconsin Electric Power Company is planning to convert four units totaling 500 MW to AFBC. These demonstration and commercial plants should better establish the feasibility of the AFBC option for new and retrofit utility application.

TVA's add-on AFBC boiler will be constructed beside the existing unit 10. The existing boiler will not be dismantled but will remain online until completion of construction of the add-on AFBC boiler.

Following startup in July 1988, a 4-year test program consisting of shakedown, parametric testing, and an extended commercial demonstration run is planned. A 6-year commercial operation period will follow, resulting in a total of 10 years of data acquisition.

The project is estimated to cost approximately $206 million including the test program. It is being funded by TVA; EPRI; Duke Power Company; Commonwealth of Kentucky; Combustion Engineering, Inc.; DOE; and utilities, coal companies, and railroads organized as the AFBC Development Corporation.

Summary

TVA believes this committee's efforts to examine the relationship between DOE's Clean Coal Technology program and the proposed strategies for the control of acid rain is important. It is imperative that funds be allocated to those processes not yet fully developed that could reduce costs over present available technology. On the other hand, risky technologies, while maybe appearing to provide some economic promise for the future, should be viewed very cautiously as reliable strategies for the control of acid rain.

TVA's plan for developing both the spray dryer/fabric filter/precipitator process and the AFBC technology is based on sound engineering design and developmental programs. Congress through DOE is now providing $30 million to our 160-MW AFBC demonstration. We strongly believe that a national commitment to spray dryer development would also be highly desirable.

Thank you very much for the opportunity to address this committee.

TABLE I

SO_2 EMISSION DATA ON TVA COAL-FIRED STEAM PLANTS

Plant	Unit	Maximum Capacity MW	Emission in 1977 k tons SO_2	Current Emission Limit lb/MBtu	Emissions in 1983	
					k tons SO_2	lb/MBtu
Allen	1-3	990	113	4.0	62	3.5
Bull Run	1	950	109	4.0	36	1.4
Colbert	1-5	1,350	229	4.0	105	3.8
Cumberland	1-2	2,600	363	5.0	312	4.7
Gallatin	1-4	1,255	155	5.0	127	4.5
John Sevier	1-4	800	96	4.0	56	2.8
Johnsonville	1-10	1,485	213	3.4	64	3.1
Kingston	1-9	1,700	178	2.8	54	1.8
Paradise	1-2	1,408	-	0.9	69	3.5
Paradise	3	1,150	-	5.7	69	4.5
Paradise total	1-3	2,558	394	3.1	138	3.9
Shawnee	1-9	1,575	-	1.2	23	1.0
Shawnee	10	175	-	1.2	30	6.0
Shawnee total	1-10	1,750	278	-	53	2.0
Watts Bar	1-4	240	34	4.0	-	3.9
Widows Creek	1-6	844	-	1.6	8	1.3
Widows Creek	7-8	1,125	-	0.9	14	0.8
Widows Creek total	1-8	1,969	189	1.2	22	0.9
Total		17,647	2,351		1,029	

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a. This is the emission limit with units 1 and 2 scrubbers in operation. However, the scrubbers did not begin commercial operation until late 1983.

b. A variance has been obtained for unit 10 from the Commonwealth of Kentucky to burn high-sulfur coal for FGD tests.

TABLE II

TVA'S SO AND PARTICULATE CONTROL PROGRAM COSTS

			Costs, M$	
Plant	Unit	Control Strategy	Capital	Annual (a)
Allen	1-3	Medium-sulfur coal, ESPs	10	6
Bull Run	1	Medium-sulfur coal, ESPs	33	5
Colbert	1-5	Medium-sulfur coal, ESPs, stacks	37	11
Cumberland	1-2	Coal cleaning, ESPs	228	57
Gallatin	1-4	Medium-sulfur coal, ESPs	58	27
John Sevier	1-4	Medium-sulfur coal, ESPs	12	2
Johnsonville	1-10	Low-sulfur coal, ESPs, stacks	94	37
Kingston	1-9	Low-sulfur coal, ESPs, stacks	71	28
Paradise	1-2	Coal cleaning, FGD)	434	103
Paradise	3	Coal cleaning, ESPs)		
Shawnee	1-9	Low-sulfur coal, baghouses, ESPs, stacks)	120	60
Shawnee	10	Baghouses, ESPs, stacks)		
Watts Bar	1-4	Medium-sulfur coal, ESPs	2	-
Widows Creek	1-6	Low-sulfur coal, ESPs, stacks)	186	53
Widows Creek	7-8	FGD)		
Total			1,285	389

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a. Approximate annual cost in 1984

The CHAIRMAN. Thank you very much.

Mr. Hawkins.

STATEMENT OF DAVID G. HAWKINS, NATURAL RESOURCES DEFENSE COUNCIL, INC.

Mr. HAWKINS. Mr. Chairman, thank you very much. I am David Hawkins from the National Resources Defense Council. I thank the committee for inviting us to be here today. As I have indicated in my testimony, congressional support for a demonstration of technologies for cleaner ways of burning coal is a longstanding program of over 20 years' duration, and environmental groups have traditionally supported that type of Government program.

We are, however, concerned with arguments that have been made in recent months, and especially here today and yesterday, arguments made by opponents of acid rain control programs that the clean coal program is the latest reason to oppose adoption of an acid rain control program. We think the claim that we have to wait on acid rain control in order to use the results of clean coal demonstrations is wrong on the merits. We also feel that it is going to undermine support for clean coal demonstration and aid by the Federal Government by undermining and dividing the broad base of political support that it now enjoys.

There are three principal claims that acid rain control opponents make regarding the relationship of clean coal demonstrations and acid rain control programs. First, they claim that current control methods are unacceptable means to pursue a control program. Second, they claim that superior methods with wide potential applicability are on the verge of commercialization. And third, they claim that the Clean Coal Grant Program will be sufficient to accelerate such commercialization while schedules in pending control bills will ensure that the impending technologies are ignored.

I would like to address each of these claims in turn about current control methods. We think they can do the job, but the argument that we have to wait for better control methods, methods that have not yet arrived, is not a new argument. Essentially the same argument was made by the utility and coal industries over 20 years ago about the same problem, control of sulfur emissions from coal. Twenty years ago the coal industry in particular pointed to an emerging technology as the solution to this problem. It was called flu gas desulfurization.

Well, now, after 15 years of refinement of flu gas desulfurization, we are being told that is not the thing we should use. Instead, we should focus on methods that have not yet arrived. Well, today's proven technologies include third generation conventional or wet FGD systems, commonly known as scrubbers, regenerable FGD systems, spray drying technology, coal cleaning, fuel switching. Together these technologies can achieve sulfur dioxide reductions of 10 to 12 million tons as called for in pending control legislation.

The coal industry and others have expressed concerns that strategies which depend on large amounts of fuel switching will result in serious social and economic disruption of families and communities that now depend on production of high sulfur coal. The National Clean Air Coalition. of which NRDC is a member, is sensitive to these concerns, and we would make a couple of points.

First, in our opinion, the amount of fuel switching that will occur under even the so-called free choice bills is overstated in current analyses. Computer models that are used in these analyses rely on knife-edge-decision rules that result in projected fuel switching whenever the assumed future cost of a lower sulfur coal is the least bit cheaper than the assumed cost of some alternative control method.

Well, these knife-edge control models ignore many economic and noneconomic variables that will tend to tilt utility managers toward continued use of their current fuels. In addition, most models use conservative high cost estimates of nonswitching alternatives such as FGD. Together these assumptions drive the computer models inexorably to predict relatively large amounts of fuel switching.

In addition, NRDC and the Clean Air Coalition have supported bills that would directly address concerns about potential fuel switching through the use of incentives or requirements to rely more heavily on nonswitching methods to meet portions of the mandated emission reduction programs, and a greater reliance on these nonswitching methods need not significantly increase projected control program costs, since, as I have mentioned, much of the switching projected by computer analyses results from very small assumed cost differences, and I have cited a recent EPA study that indicates that 30 gigawatts of scrubbing could be mandated under a control bill without any increase in the overall cost of the program. However, the control cost of programs that rely heavily on FGD and other nonswitching methods are quite easy to exaggerate.

Yesterday's testimony from the West Virginia Public Service Commission presents an example of this exaggeration. The PSC testimony claimed that if West Virginia used a nonswitching FGD strategy to comply with H.R. 4567 that utilities in the State would have to make capital expenditures of $3 billion and annual expenses of $1 billion.

While PSC testimony arrived at this figure by assuming that nearly 12,000 megawatts out of the more than 14,000 current coal-fired capacity in West Virginia would have to install full FGD systems to treat each plant's entire gas stream, that is simply not correct. In fact, to meet H.R. 4567's targets, FGD treatment would be required on only about half of this capacity. Other assumptions result in the PSC's estimates for the full cost of a scrubber based program being overstated by about a factor of three.

In addition to complaints about costs, some critics of FGD systems cite problems of reliability, complexity, and sludge disposals. While all of these were problems with some first generation systems in the early 1970's, these problems have been solved with the advanced systems that are being ordered today.

As a final observation on the feasibility of a widespread FGD retrofit program, I would like to call the committee's attention to the acid rain control program now being implemented in West Germany under legislation adopted in 1983. Every large coalfired plant in West Germany that is going to operate past 1993 is being required to install and operate a high efficiency FGD system by the beginning of 1988.

Thus less than 2 years from today West Germany will have fully implemented a wholesale FGD Retrofit Program. Scores of these systems have been ordered and are now under construction. Cost information from West Germany shows capital costs of about $100 per kilowatt for a typical 350-megawatt retrofit with lower unit cost for larger plants.

Well, NRDC and most other environmental organizations neither advocate nor oppose the universal FGD Retrofit Program or any other technology specific solution to acid rain. However, it must be noted that as West Germany, which, like the United States, depends heavily on domestic coal, and competes vigorously in international trade, is demonstrating that such a strategy is technically and economically feasible and can be implemented more rapidly than the schedules contained in any bills now pending in Congress.

The reductions required by the pending bills in Congress here would not require universal use of FGD systems, but rather could be complied with by using a mixture of the now available controls, including conventional FGD's, regenerable FGD's, spray drier systems, coal cleaning, continued use of low sulfur fuels, and to the extent Congress decides is appropriate, fuel switching.

On the second point, assessing the degree to which emerging technologies might expand the array of currently available control techniques requires a distinction between methods that can be efficiently retrofit and those that are most attractive for new plants. To state the obvious, combating acid rain means reducing emissions from the roughly 200 gigawatts of pre-NSPS fossil capacity. Thus the relevant question to ask about emerging technologies and acid rain control programs is how many technologies suitable for retrofit application is the industry today ready and willing to try to demonstrate commercially.

The answer, based upon a review of the 51 responses to DOE's $400 million grant program appears to be, unfortunately, not very many. Of the 51 responses originally submitted to DOE, only 5 appear to represent commercial scale demonstrations of retrofit technologies with any potential wide application. These proposals include furnace sorbent objection demonstrations, one type of which is Mona's LIM by Babcock and Wilcox and the Energy and Environmental Research Corp., as well as a combination proposal from TRW that would also address spray drier systems.

The Babcock and Wilcox proposal would support 2 years of additional testing of the LIM system that is already being installed right now at the Ohio Edison Edgewater plant. In addition to these three proposals, TVA, as Mr. High has mentioned, has proposed to demonstrate a spray drier system on medium high sulfur coal at its Shawnee plant. The fifth commercial scale retrofit proposal was submitted by Recovery Systems, Limited, for a regenerable FGD system that produces fertilizer. In addition to the above proposals, nine proposals for fluidized bed boilers was omitted, and while atmospheric FBC units appear to be an attractive alternative for smaller and older units that are undergoing repowering in life extension programs, it is not likely to be an economically competitive option for the many larger pre-NSBS units that were built in the 1960's and midseventies.

Moreover, at least three utilities have already independently committed to commercial construction of atmospheric FBC units, suggesting that the industry now regards this technology as demonstrated. In short, based upon current responses to the DOE Program, industry appears prepared to construct commercial scale versions of three technologies, sorbent injection systems, spray driers, and one new FGD system, and these would have some broad applicability to the retrofit market. While these systems would complement current conventional controls, there is no basis for the claim that delaying acid rain controls is either necessary of sufficient to promote rapid application of these methods.

On the third point, as I have just discussed, industry willingness to demonstrate new controls for the retrofit market is quite limited. Therefore even if the country proceeded to implement an acid rain program with absolutely no reliance on what are called emerging technologies, little in the way of benefits would be foregone. The primary value in the clean coal program, in our view, is for the long term, and not as a patch on the acid rain control bills, which have been debated now in earnest for the last 6 years, and in more general terms for the last 10 years.

The two major systems that are receiving industry attention, sorbent injection and spray drying, have already received limited commercial demonstration. Additional work can be completed in 2 to 3 years with sufficient industry interest, so that results can be made available prior to even the earliest mandatory date for achieving emission reductions in pending control bills.

For example, under H.R. 4567 reductions are required in 1993 and 1997. States have 21 months to adopt emission limits. Sources that wish to preserve an option for use of emerging technology could do so by making a conservative estimate of that technology's emission reduction potential, and seeking a source specific emission limit that would be achievable given the technology's assumed reduction potential. Sources needing decontrol by 1993 would have to make a construction decision by about 1991 based on the information presented in the DOE abstracts. Results from the sorbent injection and spray drier demos will be available by that date. Other sources will not have to control until 1997 under H.R. 4567, and those would have additional lead time.

Passage of acid rain control laws in this Congress will ensure that industry treats the potential for use of emerging technologies as a serious matter. Confronted with the need to plan for a real emission reduction program, the industry will have a genuine incentive to pool the resources required to provide prompt answers to reduce any technical risk associated with the most attractive technologies.

In contrast, if acid rain control schedules were linked to some unspecified level of proof that new technologies were demonstrated, the industry would have just the opposite incentive. They would have an enormous incentive to delay such demonstrations and to characterize the results of any demonstrations as not sufficiently conclusive. All the while damages caused by acid rain would continue. American taxpayers would not appreciate a proposal to spend billions of their dollars on a program to prove that emerging technology does not work. Yet this is the most likely outcome of any clean coal demonstration program that argues for a delay in acid rain control requirements pending adequate results.

Under such an approach, industry would know that success would bring on new regulation while failure would buy more time. As I said at the outset, Government support for cleaner ways to use coal is a good idea. It has the potential to reduce the impacts of coal use if the incentives for successful demonstrations are structured correctly, but the Clean Coal Program should not be allowed to become a pawn in the battle over acid rain controls for this would damage the chances for success in both programs.

Thank you very much.

[The prepared statement of Mr. Hawkins follows:]

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Testimony of David G. Hawkins

Natural Resources Defense Council, Inc.

before the

U.S. Senate Committee on Energy and Natural Resources

June 10, 1986

Thank you for the invitation to present NRDC's views on the relationships between the "clean coal technology" demonstration program and programs to control acid rain.

Congress has funded research and development of improved methods of reducing air pollution from coal and other fossil fuels for over twenty years. Environmental organizations such as NRDC have supported such programs as a complement to regulatory requirements because of our view that traditional market forces do not provide adequate incentives for the private sector to develop better means of controlling pollution.

The impediments to advances in control methods are particularly severe with regard to commercial demonstrations of methods for electric utility pollution control. This is due primarily to the large sums of money required to demonstrate technologies at scales of 100 megawatts or larger, as well as to the traditionally conservative engineering approach of the industry. Accordingly, we have supported federal aid for such demonstrations as a reasonable use of taxpayers' money.

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At the end of last year, Congress appropriated $400 million for a "clean coal technology" program in order to spur commercial demonstration of advanced, cleaner ways of using coal. While we support this objective of the program, we do not believe that the program is either a substitute for or a necessary prerequisite to a program to control acid rain-causing pollution.

Over the last several months, both industry supporters of the "clean coal" program, as well as previous opponents such as the Administration, have seized on the existence of this new program as the latest reason to oppose or delay the adoption of acid rain controls. These groups are now arguing that acid rain controls should be delayed so that the fruits of the "clean coal" program can be used.

The "clean coal" argument is, in effect, a replacement argument for the previous claim that acid rain controls should be delayed because additional research into the nature of the problem was an essential predicate to control action. Since the "more research" argument has been discredited by numerous independent scientific bodies, it is understandable that opponents of acid rain controls are turning to the "clean coal" argument.

However, in our view, the claim that we should delay acid rain controls to wait for "clean coal" results is wrong on the merits. Moreover, this claim is likely to weaken the "clean coal" program itself, by eroding the previous broad-based political support for that program.

Acid rain control opponents argue that we should wait for results from a "clean coal" demonstration program based on several claims that do not withstand analysis:

First, they claim that current control methods are unacceptable means to pursue a control program;

Second, they claim that superior methods with wide potential applicability are on the verge of commercialization; and

Third, they claim that the "clean coal" grant program will be sufficient to accelerate such commercialization, while the schedules in pending control bills will insure that emerging technologies are ignored.

I would like to address these claims in turn.

1. Current control methods can do the job.

The argument that we must wait for better control methods is not a new one. Essentially the same argument was made twenty years ago respecting the problem of sulfur emissions from coal by the same industries that are now most vigorously opposing acid rain controls. In 1966 and 1967, the electric utility and coal industries made this argument in order to defeat an Administration proposal for national emission standards for existing power plants and other major air pollution sources.

The coal industry in particular pointed to the emerging technology of flue gas desulfurization (FGD) as a method that, with 3-5 years of additional development work, could be used to attack the coal sulfur problem. FGD systems were developed and improved through the 1970s and are now proven and reliable means of controlling both new and existing plants.

However, now that we have been through a fifteen year period of development and refinement of FGD systems, these "emerging technologies" of twenty years ago are derided, and our attention is once more directed to methods that have not yet arrived.

Today's proven technologies include third-generation "wet" FGD systems ("scrubbers"), regenerable FGD systems, spray dryers, coal cleaning, and fuel switching. Together, these techniques can achieve sulfur dioxide (SO_2) reductions of 10-12 million tons, as called for in pending control legislation.

The coal industry and others have expressed concerns that strategies which depend on large amounts of fuel switching will result in serious social and economic disruption of families and communities that now depend on production of high sulfur coal. The National Clean Air Coalition, of which NRDC is a member, is sensitive to these concerns.

In our opinion, the amount of switching that will occur under even the so-called "free-choice" bills is overstated. Most analyses of fuel switching are based on econometric computer models that use linear programming equations to find the "least-cost" solution to a required emission reduction. These models use "knife-edge" decision rules that result in projected fuel switching whenever the assumed future cost of a lower-sulfur coal is the least bit cheaper than the assumed cost of alternative control methods. Such ""knife-edge" models ignore many economic and non-economic variables that will tilt utility managers toward continued use of their current fuel. In addition, most models use conservative (high-cost) estimates of non-switching alternatives such as FGD. Together, these assumptions drive the models inexorably to predict relatively large amounts of fuel switching.

We have supported bills that would directly address concerns about potential fuel switching through use of incentives or requirements to rely on non-switching methods to meet portions of the mandated reduction program. A greater reliance on non-switching methods need not significantly increase projected control program costs since, as I have mentioned, much of the switching projected by model analyses results from very small assumed cost differences.*/

However, the control costs of programs that rely heavily on FGD and other non-switching methods are easy to exaggerate. By using high capital cost assumptions for FGD systems, applying high capital charge rates and other misleading accounting techniques, and by assuming installation of far more FGD capacity than would be required to achieve required reductions, analysts have been able to generate very high cost estimates. A recent

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*/ Thus, for example, a recent EPA analysis indicated no difference in control costs between a "free-choice" bill and one that required 30 gigawatts of plant capacity to be "scrubbed." "Analysis of 6 and 8 Million ton and 30 Year/NSPS and 30 Year 1.2 lb. Sulphur Dioxide Emission Reduction Cases," Prepared for the Environmental Protection Agency, by ICF Incorporated, February 1986, at page 1-9.

Congressional Research Service staff critique of the Edison Electric Institute's analysis of H.R. 4567 shows that such techniques can double or triple estimated control costs.*/

Yesterday's testimony from the West Virginia Public Service Commission (PSC) presents another example of exaggerated cost estimation. The PSC testimony claims that, if West Virginia used a non-switching strategy to comply with H.R. 4567, utilities would have to make capital expenditures of $3 billion, with annual expenses of $1 billion. The PSC testimony generated these figures by assuming that nearly 12000 megawatts out of West Virginia's current 14750 megawatts of coal-fired capacity would install FGD systems to treat each plant's entire gas stream. In fact, to meet H.R. 4567's statewide-average emission requirements, FGD treatment on only about half of this capacity would be needed, even if each plant were controlled separately to meet a 1.2 pound per million Btu limit (not required by H.R. 4567 and not the most efficient strategy).**/

Second, the PSC testimony assumes capital costs for FGD systems of $250 per kilowatt. Based on actual installation experience, a figure of $150 or less per kilowatt is appropriate.*/

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*/ CRS Staff Report, "Estimating Acid Rain Control Costs: Illustrative Problems from the Recent EEI-TBS Study of H.R. 4567," April 29, 1986.

**/ Thus, for example, the PSC testimony assumes that all 2933 megawatts of the state's largest plant, John Amos, would have to be fully scrubbed to comply. However, according to the PSC testimony, John Amos' current emission rate is 1.3 pounds (PSC testimony, table 1). To meet a 1.2 pound limit, less than 9% of the Amos capacity would require FGD treatment.

These two assumptions alone result in the PSC's estimates for the cost of a full FGD compliance strategy being overstated by a factor of three. Use of available controls other than wet FGD systems on some capacity would produce still lower compliance costs.

In addition to complaints about cost, some critics of FGD systems cite problems of reliability, complexity and sludge disposal. While all of these were problems with some first-generation systems in the early 1970s, those problems have been solved with the advanced systems being ordered today.

As a final observation on the feasibility of a widespread FGD retrofit program, I would like to call the Committee's attention to the acid rain control program now being implemented in West Germany. Under legislation enacted in 1983, every large coal-fired plant in West Germany which will operate past 1993 is being required to install and operate a high-efficiency FGD system by the beginning of 1988. Thus, less than two years from today, West Germany will have fully implemented a wholesale FGD retrofit program. Scores of these systems have been ordered and are now under construction.**/ Cost information from West

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*/ See Peabody Process Systems, "Acid Deposition Control: Economical Retrofit of Wet Scrubbers to Coal Fired Boilers," March 1986, at p. 6. Exhibit 1 to this testimony.

**/ See Wm. Ellison, "Survey Report and Assessment of Utility Flue Gas Desulfurization Systems Installation in Europe," Ninth (continued next page)

Germany shows capital costs of about $100 per kilowatt for a typical 350 megawatt retrofit, with lower unit costs for larger plants.*/

NRDC and most other environmental organizations neither advocate nor oppose a universal FGD retrofit program or any other technology-specific solution to acid rain. However, West Germany, which like the United States depends heavily on domestic coal and competes vigorously in international trade, is demonstrating that such a strategy is technically and economically feasible and can be implemented more rapidly than the schedules contained in any bills now pending in Congress.

The reductions required by the pending bills would not require universal use of FGD systems, but rather, could be complied with by using a mixture of available controls, including conventional FGDs, regenerable FGDs, spray dryer systems, coal cleaning, continued use of low sulfur fuels and, to the extent Congress decides is appropriate, fuel switching.

EPA/EPRI Symposium on Flue Gas Desulfurization, Cincinnati, Ohio, June 4-7, 1985. Tables 1-4 of the Ellison paper summarize Germany's control requirements and FGD systems ordered as of year-end 1984. (Attached.)

A plant-by-plant list of the information summarized in the Ellison paper is also attached. The list, in German, contains columns that, from left to right, identify the plant name and operating company, plant size and fuel type, FGD vendor and FGD type, percentage of flue gas treated, FGD byproduct, and FGD operation date.

*/ Bernd Schärer and Norbert Haug, "The cost of flue gas desulphurization and denitrification in the Federal Republic of Germany," Fourth Seminar on the Control of Sulphur and Nitrogen Oxides from Stationary Sources, Graz, Austria, May 12-16, 1986.

2. Applicability of Emerging "Clean Coal Technologies."

Assessing the degree to which "emerging" technologies might expand the array of currently available control techniques requires a distinction between methods that can be efficiently retrofit and those that are most attractive for new plants. To state the obvious, combatting acid rain means reducing emissions from the roughly 200 gigawatts of pre-NSPS fossil capacity. Most of this capacity has operated for less than half of the plants' estimated useful life and significant reductions due to retirement cannot be expected until the end of the first quarter of the next century. Life extension programs could push reductions from retirements even further into the future.

The relevant question to ask about emerging technologies and acid rain control programs is, thus, how many technologies suitable for retrofit application is the industry today ready and willing to attempt to demonstrate commercially? The answer, based on a review of the only information made publicly available by DOE on industry responses to the current $400 million "clean coal" program, appears to be, "not very many."

Of the 51 responses originally submitted to DOE, only 5 appear to represent commercial-scale demonstrations of retrofit technologies with potentially wide application. These proposals include furnace sorbent injection demonstrations by Babcock & Wilcox and the Energy and Environmental Research Corp., as well as a combination proposal from TRW, Inc. to demonstrate, at separate sites, components of an integrated furnace sorbent injection and spray dryer system. The B&W proposal would support two years of additional testing of the sorbent injection demonstration system now being installed at Ohio Edison's Edgewater plant.

In addition to these three proposals, TVA has proposed to demonstrate a spray dryer system on medium and high sulfur coals at its Shawnee plant. It is not clear that the TVA demo is needed to commercialize application of spray dryer technology to eastern coals, given the experience already gathered at other utility and industrial plants. EPA's just-proposed NSPS for industrial boilers regards spray dryer systems as a demonstrated conventional technology capable of achieving a 90% reduction in SO_2 on any type of coal.

The fifth commercial-scale retrofit proposal was submitted by Recovery Systems, Ltd. for a regenerable FGD system that produces fertilizer.

Another advanced FGD system with retrofit potential was proposed by NOXSO Corp. However, this proposal is limited to a pilot scale of 5 megawatts electric of flue gas. This represents a scaling back from NOXSO's February 1985 submittal, which proposed a 100 megawatt commercial demonstration of this technology, contingent on locating a host utility.

In addition to the above proposals, nine proposals for fluidized bed boilers (seven atmospheric and two pressurized) were submitted. While atmospheric FBC units appear to be an attractive alternative for smaller, older units undergoing repowering for life extension programs, FBC is unlikely to be an economically competitive option for the many larger pre-NSPS units built between 1960 and the mid-1970s. Moreover, at least three utilities have already independently committed to commercial construction of AFBC units, suggesting that the industry now regards this technology as demonstrated.

In short, based on the current responses to the DOE program, industry appears prepared to construct commercial-scale versions of three technologies (sorbent injection systems, spray dryers for higher sulfur coals and one new FGD system) that may have broad applicability to the retrofit market. While use of these systems would complement current conventional controls (in our view, spray dryers are already demonstrated technology), there is no basis for a claim that delaying acid rain controls is either necessary or sufficient to promote rapid application of these methods.

3. Control Program Delays Will Delay Demonstrations of Emerging Technologies.

As I have just discussed, industry willingness to demonstrate "new" controls for the retrofit market is quite limited. Accordingly, even if the country proceeded to implement an acid rain control program with no reliance on emerging technologies, little in the way of benefits would be foregone.

The two major systems receiving industry attention, sorbent injection and spray drying, have already received limited commercial demonstration. Additional work can be completed in two to three years with sufficient industry interest so that results can be made available prior to even the earliest mandatory date for achieving emission reductions in pending control bills.

For example, under H.R. 4567, reductions are not required until 1993 and 1997. States must adopt emission limits within 21 months of enactment. Therefore, sources that wish to preserve an option for use of an emerging technology would make a conservative estimate of the technology's emission reduction potential prior to that time and seek a source-specific emission limit that would be achievable, given the technologies assumed reduction potential. Sources needing to control by 1993 would probably need to make a construction decision by 1991. Based on the information presented in the DOE abstracts, results from the sorbent injection and spray dryer demos will be available by that date.

Other sources will not have to control until 1997 under H.R. 4567 and thus will have additional lead time available. In addition, H.R. 4567 permits state plans to be revised where appropriate, so that developments in emerging technologies can be taken into account.

Passage of acid rain control laws in this Congress will insure that industry treats the potential for use of emerging controls as a serious matter. Confronted with the need to plan for a real emission reduction program, the industry will have a genuine incentive to pool the resources required to provide prompt answers to reduce any technical risks associated with emerging technologies.

In contrast, if acid rain control schedules were linked to some unspecified level of proof that new technologies were demonstrated, the industry would have an enormous incentive to delay such demonstrations and to characterize the results of any demonstrations as not sufficiently conclusive. All the while, damages caused by acid rain would continue.

Mr. Chairman, American taxpayers would not appreciate a proposal to spend billions of their dollars on a program to prove that emerging technology does not work. Yet this is the most likely outcome of any "clean coal" demonstration program that argues for a delay in control requirements pending "adequate" results. Under such an approach, industry would know that "success" would bring on new regulation while "failure" would buy more time. Taxpayers cannot be dismissed as cynics if they assume that, faced, with such incentives, industry would be tempted to spend as much time and as much taxpayers' money as they could get away with on such demonstrations.

As I said at the outset, government support for cleaner ways to use coal is a good idea. It has the potential to reduce the impacts of coal use if the incentives for successful demonstrations are structured correctly. The "clean coal" program should not be allowed to become a pawn in the battle over acid rain controls, for this would damage the prospects for success in both programs.

Thank you. I am happy to answer any questions you may have.

ACID DEPOSITION CONTROL: ECONOMICAL RETROFIT OF WET SCRUBBERS TO COAL FIRED BOILERS

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INTRODUCTION

Wet scrubbing to remove sulfur dioxide (SO_2) from flue gases generated by utility and industrial coal fired boilers is now a well-demonstrated concept and a rapidly maturing technology. The 1970 Clean Air Act required new coal fired utility power plants to install flue gas desulfurization (FGD) equipment. By 1984 there were 100 wet scrubber systems in operation on new utility boilers in the United States with an equivalent capacity of more than 40,000 MW (1). However, very few power plants built before 1970 have been retrofitted with FGD systems in the U.S.

In 1983 West Germany put acid-rain control regulations in place for all coal and oil fired power plants irrespective of age. FGD systems with a total capacity of 23,000 MW have been ordered and will be in operation by 1988. All kinds of retrofit problems have been encountered and are being resolved.

In the United States the two most widely used wet sulfur dioxide scrubbing processes are the lime and the limestone slurry scrubbing systems with pond or landfill disposal of the resulting sludge. In 1984 more than 60 systems using limestone to neutralize the scrubbed SO_2 were in operation in the United States as compared to about 40 systems using lime. Most of the wet scrubbing systems are installed on medium (1 to 3%) to high (more than 3%) sulfur coals in the Mid-West, the South and East Coast areas. Before the development of the dry scrubbing system, wet scrubbers were also installed on low sulfur applications in the West.

In recent years limestone scrubbing has been the most common choice due to the low cost of limestonne compared to lime (typically \$6 to \$10/ton vs. \$50 to \$60/ton). The limestone process offers additional advantages due to the easier process slurry dewatering. Further, there is the available option of forced oxidation of the slurry with the potential for making a commercial grade gypsum that can be used to manufacture wallboards. Almost all wet scrubber systems that are being installed in Germany will be capable of producing gypsum. On the other hand, lime systems, especially magnesium rich lime, offer lower capital costs and higher documented reliability (1) but higher operating costs due to the high cost for the lime.

In addition to the basic cost difference between lime and limestone, a number of improvements and process modifications to the limestone scrubbing process will impact annual operating costs. Some of these options are:

- o Operation with a closed water loop, i.e. no blowdown of water or slurry from the FGD plant to local lakes or rivers.
- o Enhanced SO_2 removal with organic acid buffer additives which accelerate the speed of absorption of SO_2 into the process slurry.
- o Natural or forced oxidation of slurry; landfill or commercial grade gypsum.
- o Reheat of flue gas for the purpose of reducing the steam plume emerging from the stack or no reheat at all.
- o Process slurry dewatering, disposal and utilization options.

DESCRIPTON OF THE WET SCRUBBING PROCESS

Figure 1 illustrates the most common equipment configuration used for flyash and SO_2 emissions control on a coal fired power plant. Dry flyash is first removed in an electrostatic precipitator or a baghouse. This equipment is in place on all existing coal fired power plants. For plants built prior to 1970, SO_2 removal was not required. Therefore the wet scrubber, here labled spray tower, must be retrofitted on old plants after the fan but before the stack or chimney.

The most common wet scrubber is a so-called spray tower consisting of many levels of sprays installed in a tall cylindrical or rectangular vessel. A large amount of slurry is recycled to maximize the absorption of SO_2 into the slurry phase.

Lime or limestone dissolve slowly in water and react with absorbed SO_2 to form in-soluble calcium sulfite and calcium sulfate solid particles or crystals which are removed from the slurry in settling ponds, filters or centrifuges to produce a moist sludge containing 10 to 50% water and 50 to 90% solid material.

The most common and acceptable disposal method today is to make a strong landfill material by blending the moist sludge with dry flyash from the electrostatic precipitators and dry lime to produce a low grade cement type material that hardens. Figure 2 shows this disposal method. This method permanently locks up any hazardous materials that are currently landfilled.

If there is a local market for gypsum, for example the power plant is located relatively close to a wallboard factory or a cement plant, the limestone wet scrubber FGD system can be modified to produce a commercial grade gypsum void of any harmful trace elements. Figure 3 illustrates such a modified FGD system. Air is forced into an oxidation tank which converts all calcium sulfite to calcium sulfate which precipitates in the slurry as gypsum crystals. These crystals are purified by washing the filter cake with clean water and then dewatered to less than 10% water which is acceptable to the wallboard manufacturer.

Another advantage of the gypsum process beyond converting SO_2 to a useful by-product, is that the dry flyash collected in the electrostatic precipitators can also be sold as a by-product. There is a large market for flyash used as a cement additive to enhance its strength and retard the setting.

RETROFIT OF WET SCRUBBERS TO EXISTING POWER PLANTS

When an existing coal fired boiler is to be retrofitted with a FGD system, the first basic question that must be answered is if all of the flue gas from the boiler is to be treated in the FGD system (full scrubbing) or only part of it (partial scrubbing). This decision will have very significant impact on space requirements and costs.

The requirement for reheat or no reheat of scrubbed and cooled flue gas exiting from the scrubber (typically 125°F) will also have major cost implications in terms of being able to use the existing stack and the use of steam to heat the scrubbed flue gas. Flue gas reheat is used to increase the temperature and therefore the buoyancy of the flue gas as it exits the stack. With higher stack exit temperature the steam plume will rise quicker and reduce the chance of plume "down-wash" which could result in violation of ambient SO_2 regulation in the immediate area around the power plant. Reheat of scrubbed flue gas can be done by bypassing some of the hot un-scrubbed flue gas around the FGD system and mixing this hot gas with the scrubbed gas. It can also be done by a steam to gas heat exchanger located after the scrubber. These two methods are illustrated in Figure 1.

When medium to high sulfur mid-western coals are used in combination with full scrubbing, the bypass of hot flue gas (typically 300 to 350°F) for the purpose of reheat is limited due to the SO_2 "leakage" caused by the bypass of flue gas around the scrubber (see Figure 1). If the reheat has to be accomplished by steam to gas heat exchangers, a significant amount of boiler steam has to be used which reduces the generating capacity of the steam turbine correspondingly.

From a manufacturers point of view and speaking in general terms, the most economical retrofit system is partial scrubbing with limestone for SO_2 neutralization and a performance enhancement additive (organic acid buffer), thereby providing a very high SO_2 removal efficiency in the scrubber (95 to 98%). Further, bypass reheat for an overall SO_2 removal efficiency of 50 to 70%, a final stack temperature of 170 to 190°F and continued use of the existing stack. To minimize the space requirement and cost of the slurry dewatering equipment and landfill or to produce useful by-product gypsum, forced oxidation should be included. A plot plan of such a retrofit installation is shown in Figure 4. The existing stack can be used if a corrosion resistant metal or plastic liner is installed.

If the old electrostatic precipitator (ESP) performance is substandard, the scrubber will remove additional flyash. Typically a spray tower will remove 30 to 50% of the flyash escaping old ESP's. If higher flyash removal efficiency was required, the spray tower design can be modified resulting in removal efficiencies of 50 to 90% of the flyash escaping the ESP.

Table 1 shows the overall annual consumption and generation rates for a 500 MW plant firing a high sulfur Mid-Western coal. If there is no SO_2 removal this plant would generate about 90,000 tons/yr. With 75% removal in a partial scrubbing system this is reduced to 22,370 tons/yr. Note also that the plant generates 126,320 tons/yr of flyash and 180,600 tons/yr of gypsum.

FGD RETROFIT COSTS

Actual costs from three recent Peabody Process Systems FGD installations (2) were averaged and the costs per KW of generating capacity are shown in Table 2. The average generating capacity was 600 MW. The FGD supplier scope adds up to about $102/kw and witn other costs associated with the project, the installed cost increases to about $148/kw. Electric Power Research Institute (EPRI) guidelines (5) were used for site work, architect and engineering fees, etc. For retrofitted systems one should keep in mind that the site preparation costs would be highly variable, depending upon the required demolition and congestion at each specific site; however $150/kw should be a relatively conservative cost when one considers partial scrubbing only.

PEDCO (1) surveys of all installed and operating FGD systems in this country have reported average cost (1984 dollars) of $108.8/kw. EPRI (5) has reported a new installed cost with full scrubbing of $177/kw also in 1984 dollars.

The amount of flue gas that needs to be scrubbed for a given overall SO_2 removal efficiency and scrubber module efficiency is shown in Table 3. SO_2 removal in the range of 50 to 70% has been discussed for retrofit acid deposition control. With given overall SO_2 and scrubber removal efficiencies, the amount of bypass of hot (300°F) gas and the stack temperature after reheat was calculated. To protect the old ducts and the stack, reheat temperature increase (T) of 40 to 60°F would probably be required. For example, the first line in Table 2; with a 50% reduction of SO_2, 44.4% of the flue gas will be bypassed and 55.6% of the flue gas will be scrubbed with a 90% efficiency. The final stack temperature will be 211°F or a reheat T of 84°F. Based upon the amount of gas scrubbed the capital cost will be 55 to 60% of $147/kw or $80 to $90/kw or $40 to $45 million for the 500 MW plant.

With the above cost assumptions and bypass reheat only, the annual operating costs can be calculated as shown in Table 4. The coal's sulfur content was assumed to be 3.8%, ash content 13.8% and heating value 11,200 Btu/lb i.e., a typical high sulfur Mid-Western coal. For the case studied here, the annual first year operating costs are 6.17 mills/kwh or 0.617 cent/kwh. EPRI cost estimates in 1982 (5) were calculated to be 6.82 mills/kwh which includes steam reheat so 6.17 with bypass reheat should be realistic. Based upon this, the operating cost for each partial scrubbing case was calculated as shown in Table 3. Steam reheat will add significant operating cost, typically 1.2 to 2 mills/kwh.

From Table 3 it can be concluded that at 50% reduction, almost 1/2 of the flue gas can bypass the scrubber. At 70% reduction and 97.5% module efficiency (which is feasible with organic acid buffer performance enhancement) 28.2% of the gas would be bypassed and 71.8% would be scrubbed, still giving a 53°F reheat. Further, as seen, 80% reduction is probably not feasible without adding steam reheat.

The above costs can be related to the amount of SO_2 removed (\$/ton of SO_2 removed) and the coal consumed (\$/ton of coal) as follows:

\$/ton of SO_2 removal

= (mills/kwh) x (HV/HR) x (100/%S) x (100/SO_2 EFF)

\$/ton of coal fired

= 2 x (mills/kwh) x (HV/HR)

where

HV = coal heating value, assumed to be 11,200 Btu/hr

HR = power plant heat rate, typically 10,500 Btu/kwh for an average old coal fired station.

%S = percent sulfur in the coal, assumed here to be 3.8%

SO_2 EFF = the overall SO_2 removal efficiency at the plant, for full scrubbing typically 90 to 98% and for partial scrubbing 50 to 75%.

If we consider the two cases, full scrubbing at 95% and partial scrubbing at 70% SO_2 removal the operating costs work out as follows:

Full scrubbing at 95% SO_2 removal:

FGD operating costs in cents/kwh = 0.617

\$/ton of SO_2 removed

= 6.167 x (11,200/10,500) x (100/3.8) x (100/95)

= \$182.22

\$/ton of coal fired

= 6.167 x (11,200/10,500) x 2

= \$13.16

Partial scrubbing at 70% SO_2 removal:

From Table 3, the operating cost with overall efficiency of 70% and scrubber module efficiency of 95% is 4.55 mill/kwh or 0.455 cents/kwh.

FGD operating costs in cents/kwh = 0.455

\$/ton of SO_2 removed

= 4.55 x (11,200/10,500) x (100/3.8) x (100/70)

= \$182.46

\$/ton of coal fired

= 4.55 x (11,200/10,500) x 2

= \$9.71

Typical power costs for consumers in the mid-western cities is 8 cents/kwh and typical "local" high sulfur coal cost for the power companies is 30 to 40 dollars/ton. So FGD costs would represent about 6% of current consumer electricity costs and add about \$10 per ton of coal fired. Low sulfur coal, an alternate to reduce SO_2 emissions cannot generally be supplied in large quantities to the Mid-West for a \$10/ton differential. Some Mid-West utilities are paying \$55/ton and more for Western coal.

If the gypsum could be sold for example at \$5/ton (dry) it would produce revenue and reduce disposal costs (typically \$8/ton). This combined effect would reduce the annual operating cost for our example by 0.77 mills/kwh. If the flyash could be sold for \$3/ton, this would reduce the operating costs by an additional 0.45 mills/kwh.

The above annualized costs are based upon first year operating costs with 1985 dollars and an annual fixed charge on capital of 15%. EPRI have typically reported the annualized cost as "levelized" or present worth cost over 30 year plant life with 12.5% interest and 8.5% inflation (5). This assumption makes a big difference in annual operating costs. To "levelize" the costs on this basis requires a multiplier of 2.31 on first year costs. Further, EPRI have published cost guidelines to estimate retrofit costs for wet FGD scrubbers assuming full scrubbing (6). This retrofit guideline can result in some very high capital and annual operating costs. Table 5 summarize the different reported capital and operating costs.

There will be cases where retrofit costs for full scrubbing will be high, however we believe that if partial scrubbing is retrofitted to old plants the capital costs will be more in line with new installation costs. The concept of bypass reheat will eliminate the use of steam for this purpose, reduce the annual operating costs and make it possible to use the old stack.

It will be very interesting to see how the retrofit costs in West Germany for full scrubbing with wet scrubbers will work out. Many power plant sites there are very congested and in heavily populated areas. From what we know about projects awarded there, the cost will be lower than for new installations in this country.

CONCLUSIONS

From the above analysis and the experienced gained over the last ten years, cost effective wet FGD systems can be built and retrofitted for medium to high sulfur coal fired boilers. The most attractive wet scrubbing option is limestone scrubbing with forced oxidation and landfill disposal. If flyash and/or gypsum are saleable by-products in a particular area, this option becomes very cost effective.

Very cost and space effective partial scrubbing systems can be built with bypass reheat thereby making it possible to use existing ducts and stacks.

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TABLE 1

ANNUAL CONSUMPTIONS AND GENERATIONS FOR A 500 MW COAL FIRED POWER PLANT

Coal Feed (dry tons/yr)	1,177,300
Limestone Consumption (dry tons/yr)	142,875
Flyash Generated	126,320
Uncontrolled SO_2 (dry tons/yr)	89,480
SO_2 Emission with 75% Removal (tons/yr)	22,370
Gypsum Generated (dry tons/yr)	180,600

Assumptions:

500 MW generating capacity firing 3.8% sulfur coal with 13.4% ash and a heating value of 11,200 Btu/lb. 70% annual load factor and 75% overall SO_2 removal.

Table 2 Total FGD Plant Investment (actual costs)

Medium to High Sulfur Coal. Limestone Scrubbing with Forced Oxidation and Sludge Fixation for Landfill Disposal
1983-1984 Dollars

Average plant size is 600 MW.	Avg. 3 Plants
Alkali Feed & Prep.	$ 12.06/kw
Gas Handling	11.35
SO_2 Absorber	33.29
Slurry Oxidizer	2.42
Waste Handling	18.63
Foundations	2.18
Buildings	4.60
Miscellaneous	0.77
Engineering & Project Management	10.39
Construction Super.	2.17
Startup	0.51
Total Process Capital (TPC)	$ 101.71/kw
General Site Work	16.00
A-E Fees @15% of TPC	15.26
Sub-Total	$ 132.97/kw
5% Contingency	6.65
Total Plant Cost	$ 139.62/kw
Interest During Const. (12.5%) & Escalation (8.5%); Factor 0.0567 of Total Cost	7.91
Total Plant Investment	$ 147.53/kw

Table 3 Retrofit Slip-Stream Scrubbing Costs

500 MW Unit, Firing High Sulfur Coal
Capital Cost = $147.5/kw of Scrubbed Capacity
Operating Cost = 6.17 Mills/kwh of Scrubbed Capacity

Overall Eff. (%)	Scrubber Module Eff. (%)	Reheat Bypass (%)	Scrubber Flow (ACFM Sat.)	Emission (Lbs/mm btu)	Stack Temp. (°F)	Reheat ΔT (°F)	Capital Cost (1) ($/kw)	Operating Cost (2) (Mills/kwh)
50	90.0	44.4	2 x 499.221	4.63	211	94	83.4	3.43
50	95.0	47.4	2 x 472.946	4.63	217	90	77.6	3.24
50	97.5	48.7	2 x 460.820	4.63	219	92	75.7	3.16
60	90.0	33.3	2 x 599.065	3.71	189	62	98.4	4.11
60	95.0	36.8	2 x 567.536	3.71	196	69	93.2	3.90
60	97.5	38.5	2 x 552.983	3.71	199	72	90.7	3.79
70	90.0	22.2	2 x 698.910	2.78	168	41	114.6	4.80
70	95.0	26.2	2 x 662.125	2.78	176	49	108.9	4.55
70	97.5	28.2	2 x 645.147	2.78	180	53	105.9	4.43
75	95.0	21.1	2 x 709.422	2.32	166	39	116.4	4.87
75	97.5	23.1	2 x 691.229	2.32	170	43	113.4	4.74
80	97.5	17.9	2 x 737.311	1.85	160	33	121.1	5.06
80	98.5	18.8	2 x 729.625	1.85	162	35	119.8	5.01
90	90.0	0	2 x 898.601	0.93	127	0	147.5	6.17

(1) Based upon 500 MW Generating Capacity
(2) Based upon 500 MW Generating Capacity and 6.132 Hrs/Yr.

Table 4 Annual 1st Year Operating Costs

500 MW Plant, High Sulfur Coal

Plant Investment = $150 x 1000 x 0.15/6.132	=	3.669 Mills/kwh
Consumables from Table 2 (1)		1.955
Additional DBA for 95% Efficiency Scrubbing		0.380
Manpower = $50,000 x 10/(500 x 6.132)	=	0.163
Total Annual Cost (First Year)		6.167 Mills/kwh = 0.6167 ¢/kwh

Assumptions:

Fixed Charge Rate = 15%/yr.
Operating Labor = $18.30 with 30% overhead = $50,000/yr.
Operating Hrs. Per Year = 24 x 365 x 0.7 = 6.132 hrs/yr.
Manpower Requirements = 2 men/shift; 5 shifts = 10 men

(1) Landfill disposal of flyash and sludge included.

TABLE 5

CAPITAL & OPERATING COSTS
In Constant 1984 Dollars

Limestone Wet FGD with Forced Oxidation and Landfill Disposal

PEDCO Report (Ref. 1)	Dec. 84 & Capital	$ 108.8/kW
	Total Operating	6.70 mills/kWh
PPSI Report (Ref. 2)	Capital	$ 165.0/kW
	Total Operating	7.36 mills/kWh
Rubin Report (Ref. 3)	Capital	$ 237.0/kW
	Total Operating	10.40 mills/kWh
CH^{2}M Hill Report (Ref. 4)	Capital	$ 277.7/kW
	Total Operating	13.91 mills/kWh
EPRI Cost 84 $'s (Ref. 5)	Capital	$ 177.0/kW
	Total Operating	6.83 mills/kWh
EPRI Levelized * Costs (Ref 5)	Capital	$ 177.0/kW
	Total Operating	15.80 mills/kWh

* Levelized at 12.5% int., 8.5% inflation over 30 yrs.
Factor - 2.31

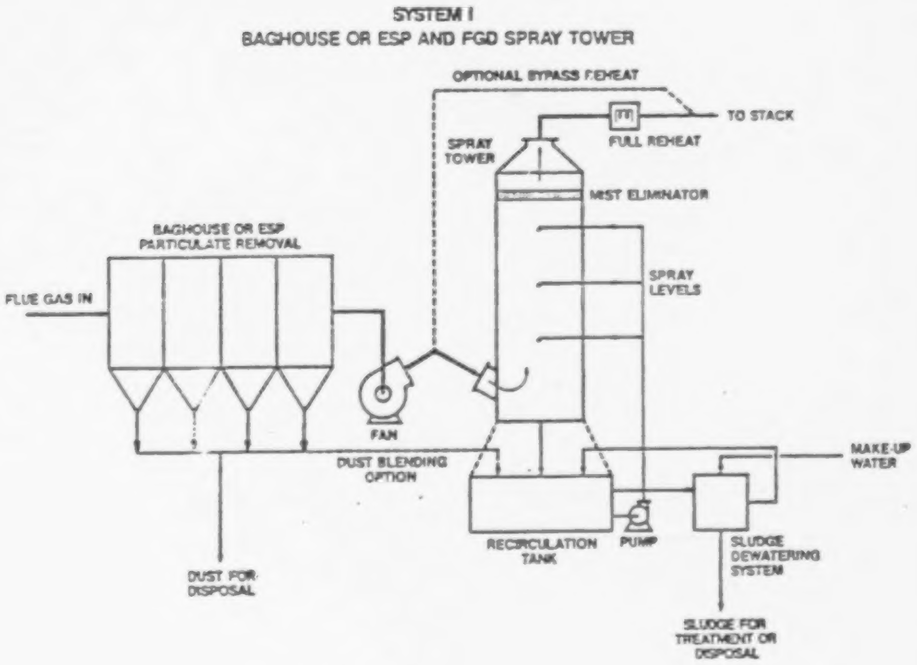

FIGURE 1

TYPICAL AIR POLLUTION CONTROL SYSTEM
CONFIGURATION FOR COAL FIRED BOILERS

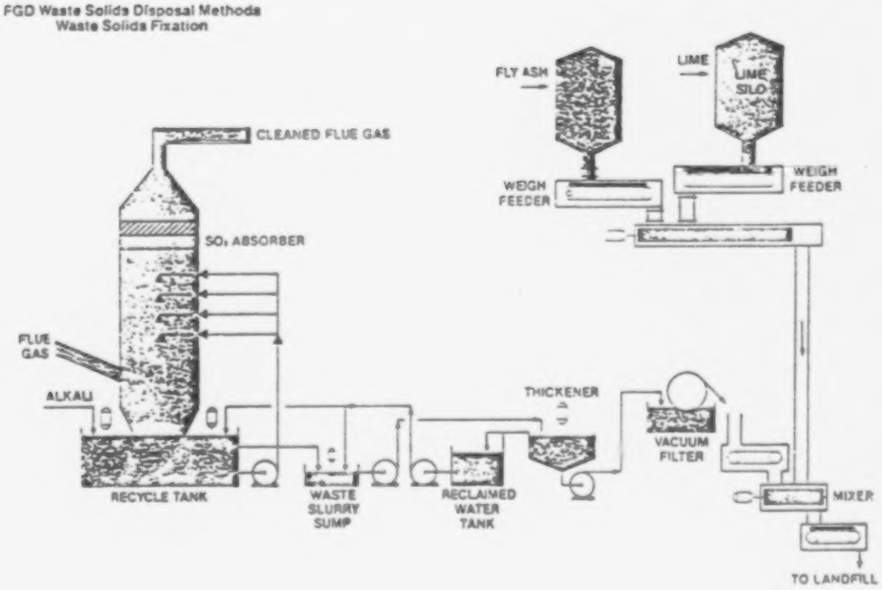

FIGURE 2

WET FGD SCRUBBING SYSTEM WITH LANDFILL DISPOSAL

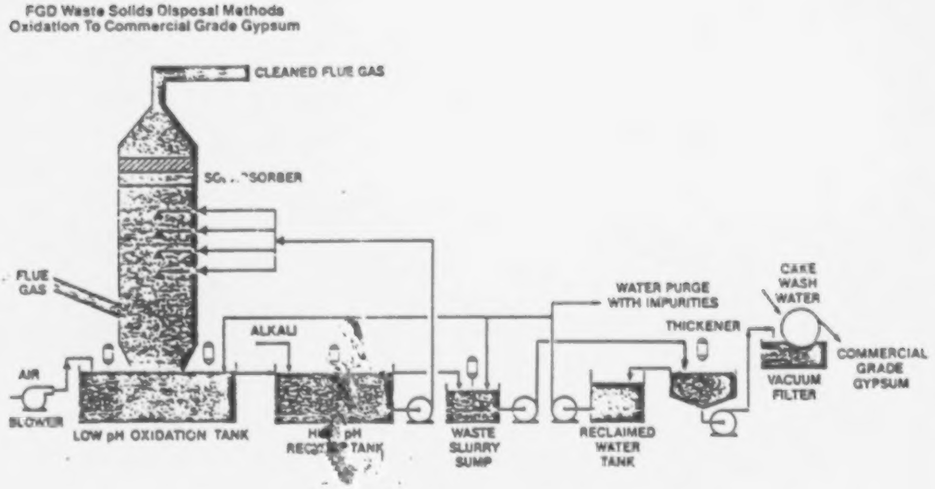

FIGURE 3

WET FGD SCRUBBING SYSTEM
PRODUCING COMMERCIAL GRADE GYPSUM

FIGURE 4

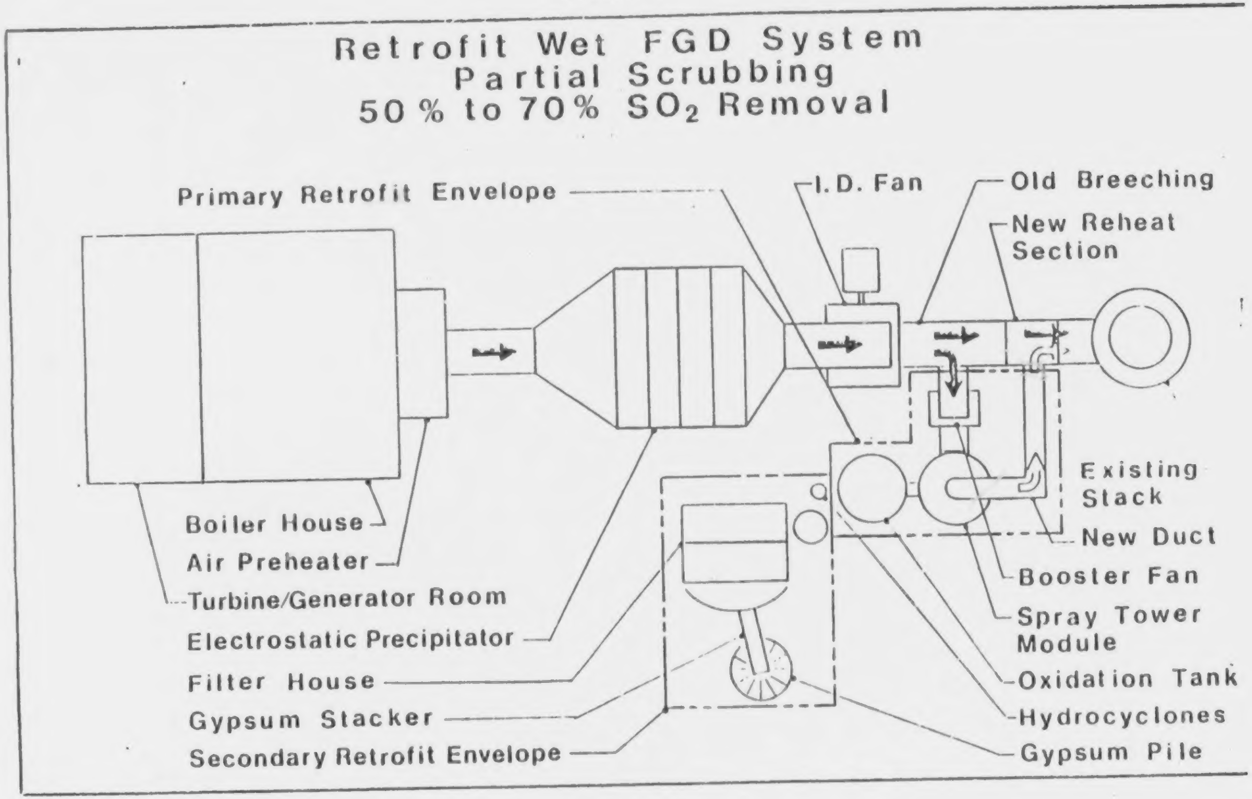

FIGURE 4

TABLE 1. POPULATION OF EXISTING WEST GERMAN COAL AND OIL FIRED BOILERS

Size, MW(e)	Number	Aggregate MW(e)	Average MW(e)
Over 300	41	18,400	450
135-300	91	17,800	195
75-135	95	9,900	104
30-75	378	18,500	49
9-30	548	10,600	19
Over 9	1153 (Tot.)	75,200 (Tot.)	65

TABLE 2. FEDERAL SO_2 CONTROL REQUIREMENTS FOR WEST GERMAN COAL-FIRED BOILERS

	Emission limit			
Size MW(e)	mg/Nm^3 (Ap.lb/MMBtu)	% removal	Deadline	Ap.No. existing
Over 110	400 (0.5Avg.)	85	7/1/88	160
35 to 110	2,000 (2.5Avg.)	60	4/1/93	370
18 to 35	2,000 (2.5Avg.)	-	4/1/93	300

from:

Survey Report and Assessment
of Utility Flue Gas Desulfurization
System Installations in Europe,

by William Ellison

TABLE 3. FGD COMMITMENTS IN WEST GERMANY (END OF 1984)

Status	Aggregate MW(e)	No. of Install.	Average MW(e)
In operation	4,700	13	360
Purchased but not in operation	29,800	102	290
Total	34,500	115	300

TABLE 4. PRINCIPAL PROCESSES USED

Process	Aggregate MW(e)	No. of Install.	Average MW(e)
Kawasaki Magnesia Gypsum	8,200	27	300
Mitsubishi Lime/Limestone	4,600	16	290
Chemico-Mitsui (GEESI)	5,600	15	370
Research Cottrell Double-Loop	3,600	9	400
Saarberg-Hoelter Buff.Clear Liq.	5,500	21	260
Bischoff Single-Loop	3,700	17	220
Total	31,200	105	300

Rauchgasentschwefelungsanlagen in der Bundesrepublik Deutschland (Stand 31. 12. 1984)

Kraftwerk Betreiber	Leistung Brennstoff	REA-Hersteller Verfahren	REA-Kapazität	Endprodukt Verwendung	Inbetriebnahme
Wilhelmshaven NWK	750 MW$_{el}$ Steinkohle	Bischoff Kalk-/Kalksteinwäsche	20 %	Gipsschlamm Deponie	seit 1977 in Betrieb wird zur Zeit ersetzt
		Bischoff Kalk-/Kalksteinwäsche	55 %	Gips Baustoffindustrie	seit 1982 in Betrieb
		Bischoff Kalk-/Kalksteinwäsche	45 %	Gips Baustoffindustrie	In Bau Inbetriebnahme Ende 1985
Zolling, Block 5 Isar-Amperwerke	450 MW$_{el}$ Steinkohle	Bischoff Kalksteinwäsche	100 %	Gips Baustoffindustrie	In Bau Inbetriebnahme Juni 1985
GKK Kiel Gemeinschafts-KW Kiel	325 MW$_{el}$ Steinkohle	Bischoff Kalk-/Kalksteinwäsche	100 %	Gips Baustoffindustrie	Baubeginn 1985 Inbetriebnahme April 1987
Bremen-Farge NWK	325 MW$_{el}$ Steinkohle	Bischoff Kalk-/Kalksteinwäsche	100 %	Gips Baustoffindustrie	Baubeginn 1986 Inbetriebnahme Juni 1988
Frimmersdorf RWE	12 x 150 MW$_{el}$ Braunkohle	Bischoff Kalksteinwäsche	12 x 100 %	Gips Deponie	Baubeginn 1985 Inbetriebnahme 1987/88
KW Mitte Ludwigshafen BASF	700 MW$_{th}$ Steinkohle	Davy McKee Wellmann-Lord	100 %	Verflüssigtes SO_2 Weiterverarbeitung	Inbetriebnahme Anfang 1988
Offleben II, Block C BKB	325 MW$_{el}$ Braunkohle	Davy McKee Wellmann-Lord	100 %	Schwefel Chemische Industrie	Baubeginn 1985 Inbetriebnahme Juni 1987
Buschhaus BKB	350 MW$_{el}$ Braunkohle	Davy McKee Wellmann-Lord	100 %	Schwefel Chemische Industrie	Baubeginn 1985 Inbetriebnahme 1987
Mehrum Preußenelektra	700 MW$_{el}$ Steinkohle	Deutsche Babcock Kalk-/Magnesiumwäsche (KHI-Babcock)	33 %	Gips Baustoffindustrie	seit 1982 in Betrieb
		Deutsche Babcock Kalk-/Magnesiumwäsche (KHI-Babcock)	50 %	Gips Baustoffindustrie	in Bau Inbetriebnahme 1985
Heilbronn, Block 7 EVS	720 MW$_{el}$ Steinkohle	Deutsche Babcock Kalksteinwäsche (KHI-Babcock)	50 %	Gips Baustoffindustrie	In Bau Inbetriebnahme 1985
		Deutsche Babcock Kalksteinwäsche (KHI-Babcock)	50 %	Gips Baustoffindustrie	In Bau Inbetriebnahme 1986
Hafen, Bremen Stadtwerke Bremen	300 MW$_{el}$ Steinkohle	Deutsche Babcock Kalksteinwäsche (KHI-Babcock)	100 %	Gips Baustoffindustrie	Baubeginn 1985 Inbetriebnahme 1986
Hafen, Bremen Stadtwerke Bremen	150 MW$_{el}$ Steinkohle	Deutsche Babcock Kalksteinwäsche (KHI-Babcock)	100 %	Gips Baustoffindustrie	Baubeginn 1986 Inbetriebnahme 1987
Heilbronn, Blöcke 3 bis 6 EVS	2 x 110 MW$_{el}$ 2 x 125 MW$_{el}$ Steinkohle	Deutsche Babcock Kalksteinwäsche (KHI-Babcock)	100 %	Gips Baustoffindustrie	Baubeginn 1985 Inbetriebnahme 1987
Staudinger Preußenelektra	300 MW$_{el}$ Steinkohle	Deutsche Babcock Kalksteinwäsche (KHI-Babcock)	100 %	Gips Baustoffindustrie	Baubeginn 1985 Inbetriebnahme 1987
Herne STEAG	2 x 150 MW$_{el}$ 1 x 300 MW$_{el}$ Steinkohle	Deutsche Babcock Kalksteinwäsche (KHI-Babcock)	100 %	Gips Baustoffindustrie	Baubeginn 1985 Inbetriebnahme 1986
Lünen STEAG	1 x 150 MW$_{el}$ 1 x 350 MW$_{el}$ Steinkohle	Deutsche Babcock Kalksteinwäsche (KHI-Babcock)	100 %	Gips Baustoffindustrie	Baubeginn 1986 Inbetriebnahme 1987
West, Voerde STEAG	2 x 350 MW$_{el}$ Steinkohle	Deutsche Babcock Kalksteinwäsche (KHI-Babcock)	100 %	Gips Baustoffindustrie	Baubeginn 1985 Inbetriebnahme 1987
Walsum STEAG	1 x 150 MW$_{el}$ 1 x 410 MW$_{el}$ Steinkohle	Deutsche Babcock Kalksteinwäsche (KHI-Babcock)	100 %	Gips Baustoffindustrie	Baubeginn 1986 Inbetriebnahme 1988
Weisweiler RWE	2 x 150 MW$_{el}$ 2 x 300 MW$_{el}$ 2 x 600 MW$_{el}$ Braunkohle	Deutsche Babcock Kalksteinwäsche (KHI-Babcock)	100 %	Gips Deponie	Baubeginn 1985–86 Inbetriebnahme 1987–88

Fortsetzung: Rauchgasentschwefelungsanlagen in [illegible] Bundesrepublik Deutschland (Stand 31. 12. 1984)

Kraftwerk Betreiber	Leistung Brennstoff	REA-Hersteller Verfahren	REA-Kapazität	Endprodukt Verwendung	Inbetriebnahme
Goldenbergwerk RWE	2 x 600 MW_{el} Braunkohle	Deutsche Babcock Kalksteinwäsche (KHI-Babcock)	100 %	Gips Deponie	Baubeginn 1986–87 Inbetriebnahme 1988–89
Wehrden, Völklingen Kraftwerk Wehrden	110 MW_{el} Steinkohle	Fläkt Drypac-Sprühsorption	100 %	technisches Sulfit Deponie	Baubeginn September 1985 Inbetriebnahme Dez. 1986
HKW Sandreuth, Nürnberg EWAG Nürnberg	3 x 106 MW_{th} Steinkohle	Fläkt Drypac-Sprühsorption	100 %	technisches Anhydrid Zementindustrie	Baubeginn August 1985 Inbetriebnahme Januar 1987
Rheinhafen-Dampfkraftwerk Block 7, Karlsruhe Badenwerk	540 MW_{el} Steinkohle	Knauf-Research Cottrell/EVT Kalksteinwäsche (KRC)	50 %	Gips Baustoffindustrie	In Bau Inbetriebnahme April 1985
		Knauf-Research Cottrell/EVT Kalksteinwäsche (KRC)	50 %	Gips Baustoffindustrie	In Bau Inbetriebnahme 3. Q. 1986
Altbach/Deizisau, Block 5 Neckarwerke	420 MW_{el} Steinkohle	Knauf-Research Cottrell/EVT Kalksteinwäsche (KRC)	50 %	Gips Baustoffindustrie	In Bau Inbetriebnahme Sept. 1985
		Knauf-Research Cottrell/EVT Kalksteinwäsche (KRC)	50 %	Gips Baustoffindustrie	In Bau Inbetriebnahme 4. Q. 1986
Franken II, Blöcke 1 und 2, Erlangen Großkraftwerk Franken	2 x 200 MW_{el} Steinkohle	Knauf-Research Cottrell/EVT Kalksteinwäsche (KRC)	2 x 100 %	Gips Baustoffindustrie	Baubeginn 1985 Inbetriebnahme 1986
Aschaffenburg, Blöcke 21 und 31 Bayernwerk	2 x 150 MW_{el} Steinkohle	Knauf-Research Cottrell/EVT Kalksteinwäsche (KRC)	100 %	Gips Baustoffindustrie	Baubeginn Mitte 1985 Inbetriebnahme 1986
Neurath, Blöcke D und E, Grewenbroich RWE	1 200 MW_{el} Braunkohle	Knauf-Research Cottrell/EVT Kalksteinwäsche (KRC)	100 %	Gips mit 10 % Restfeuchte Ablagerung im Tagebau	Baubeginn Anfang 1985 Inbetriebnahme Anfang 1988
Franken II, Block 3, Erlangen Großkraftwerk Franken	700 MW_{el} Steinkohle	Knauf-Research Cottrell/EVT Kalksteinwäsche (KRC)	100 %	Gips Baustoffindustrie	noch offen
HKW Mitte Stadtwerke Braunschweig	50 MW_{el} + 110 MW_{th} Steinkohle	Niro Atomizer Kalkwäsche/ Sprühtrocknung	100 %	Kalziumsulfit/ Kalziumsulfat Baustoffindustrie	Baubeginn Ende 1985 Inbetriebnahme Ende 1986
Weiher II Saarbergwerke	150 MW_{el} Steinkohle	Saarberg-Hölter Kalkwäsche (SHU)	125 000 m^3/h	Gips Baustoffindustrie	seit 1974 in Betrieb
Weiher III Saarbergwerke	707 MW_{el} Steinkohle	Saarberg-Hölter Kalkwäsche (SHU)	32 %	Gips Baustoffindustrie	seit 1979 in Betrieb
		Saarberg-Hölter Kalkwäsche (SHU)	18 %	Gips Baustoffindustrie	seit 1983 in Betrieb
Völklingen Saarbergwerke	230 MW_{el} Steinkohle	Saarberg-Hölter Kalkwäsche (SHU)	100 %	Gips Baustoffindustrie	seit 1982 in Betrieb
Lichterfelde, West-Berlin BEWAG	150 MW_{el} Öl	Saarberg-Hölter Kalkwäsche (SHU)	100 %	Gips Baustoffindustrie	seit 1982 in Betrieb
Lichterfelde, West-Berlin BEWAG	150 MW_{el} Öl	Saarberg-Hölter Kalkwäsche (SHU)	100 %	Gips Baustoffindustrie	seit 1983 in Betrieb
Bexbach Saarbergwerke, Bayernwerk, Badenwerk, EVS	750 MW_{el} Steinkohle	Saarberg-Hölter/Lurgi Kalksteinwäsche (SHL)	35 %	Gips Baustoffindustrie	seit 1983 in Betrieb
Bexbach Saarbergwerke, Bayernwerk, Badenwerk, EVS	750 MW_{el} Steinkohle	Saarberg-Hölter/Lurgi Kalksteinwäsche (SHL)	35 %	Gips Baustoffindustrie	seit 1984 in Betrieb
Reuther, West-Berlin BEWAG	300 MW_{el} Steinkohle	Saarberg-Hölter-Lurgi Kalksteinwäsche (SHL)	100 %	Gips Baustoffindustrie	Baubeginn 1985 Inbetriebnahme 1987
Reuther, West-Berlin BEWAG	300 MW_{el} Steibkohle	Saarberg-Hölter-Lurgi Kalksteinwäsche (SHL)	100 %	Gips Baustoffindustrie	Baubeginn 1986 Inbetriebnahme 1988
Heyden IV Preußenelektra	800 MW_{el} Steinkohle	Saarberg-Hölter-Lurgi Kalksteinwäsche (SHL)	100 %	Gips Baustoffindustrie	In Bau Inbetriebnahme 1987
Neurath, Blöcke A, B, C RWE	3 x 300 MW_{el} Braunkohle	Saarberg-Hölter-Lurgi Kalksteinwäsche (SHL)	3 x 100 %	Gips Baustoffindustrie oder Deponie	Baubeginn 1986 Inbetriebnahme 1987
Neurath, Block F RWE	600 MW_{el} Braunkohle	Saarberg-Hölter-Lurgi Kalksteinwäsche (SHL)	2 x 50 %	Gips Baustoffindustrie oder Deponie	Baubeginn 1987 Inbetriebnahme 1988
Neurath, Block G RWE	600 MW_{el} Braunkohle	Saarberg-Hölter-Lurgi Kalksteinwäsche (SHL)	2 x 50 %	Gips Baustoffindustrie oder Deponie	Baubeginn 1988 Inbetriebnahme 1989
Bergkamen A STEAG	747 MW_{el} Steinkohle	Steinmüller Kalkwäsche (Chemico)	50 %	Gips Baustoffindustrie	seit Ende 1981 in Betrieb
		Steinmüller Kalkwäsche (Chemico)	50 %	Gips Baustoffindustrie	seit April 1984 in Betrieb

Fortsetzung: Rauchgasentschwefelungsanlagen in der Bundesrepublik Deutschland (Stand 31. 12. 1984)

Kraftwerk Betreiber	Leistung Brennstoff	REA-Hersteller Verfahren	REA-Kapazität	Endprodukt Verwendung	Inbetriebnahme
Werne VEW	750 MW_{el} Steinkohle/Gas	Steinmüller Kalkwäsche (Chemico)	2 x 36 %	Gips Baustoffindustrie	seit Oktober 1984 in Betrieb
		Steinmüller Kalkwäsche (Chemico)	28 %	Gips Bauindustrie	In Bau Inbetriebnahme Mitte 1987
Voerde A STEAG	707 MW_{el} Steinkohle	Steinmüller Kalkwäsche (Chemico)	76 %	Gips Baustoffindustrie	seit Ende 1982 in Betrieb
		Steinmüller Kalkwäsche (Chemico)	24 %	Gips Baustoffindustrie	In Bau Inbetriebnahme Ende 1985
Voerde B STEAG	707 MW_{el} Steinkohle	Steinmüller Kalkwäsche (Chemico)	100 %	Gips Baustoffindustrie	In Bau Inbetriebnahme Ende 1985
Niederaußem RWE	9 x 300 MW_{el} Braunkohle	Steinmüller Kalksteinwäsche (Chemico)	9 x 100 %	Gips Deponie	Baubeginn Juli 1985 Inbetriebnahme Juli 1987 bis Juli 1988
Scholven F VKR	740 MW_{el} Steinkohle	Thyssen Engineering Kalkwäsche (Thyssen-Mitsubishi)	25 %	Gips Baustoffindustrie	seit 1979 in Betrieb
		Thyssen Engineering Kalkwäsche (Thyssen-Mitsubishi)	2 x 25 %	Gips Baustoffindustrie	seit 1982 in Betrieb
		Thyssen Engineering Kalkwäsche (Thyssen-Mitsubishi)	25 %	Gips Baustoffindustrie	Baubeginn 2. Q. 1985 Inbetriebnahme 1. Q. 1987
HKW Buer VKR	82 MW_{el} + 244 MW_{th} Steinkohle	Thyssen Engineering Kalksteinwäsche (Thyssen-Mitsubishi)	100 %	Gips Baustoffindustrie	In Bau Inbetriebnahme 1985/86
Marl VKR	77 MW_{el} Steinkohle	Thyssen Engineering Kalkwäsche (Thyssen-Mitsubishi)	100 %	Gips Baustoffindustrie	Baubeginn 2. Q. 1985 Inbetriebnahme 4. Q. 1986
Knepper C VKR	370 MW_{el} Steinkohle	Thyssen Engineering Kalkwäsche (Thyssen-Mitsubishi)	100 %	Gips Baustoffindustrie	Baubeginn 4. Q. 1985 Inbetriebnahme 4. Q. 1987
Datteln, Blöcke 1 bis 3 VKR	303 MW_{el} Steinkohle	Thyssen Engineering Kalkwäsche (Thyssen-Mitsubishi)	100 %	Gips Baustoffindustrie	Baubeginn 4. Q. 1985 Inbetriebnahme 4. Q. 1987
Scholven, Blöcke B, C, D u. E VKR	4 x 370 MW_{el} Steinkohle	Thyssen Engineering Kalkwäsche (Thyssen-Mitsubishi)	4 x 100 %	Gips Baustoffindustrie	Baubeginn 4. Q. 1985 Inbetriebnahme 4. Q. 1987
Westerholt VKR	300 MW_{el} Steinkohle	Thyssen Engineering Kalkwäsche (Thyssen-Mitsubishi)	100 %	Gips Baustoffindustrie	Baubeginn 4. Q. 1985 Inbetriebnahme 4. Q. 1987
Shamrock VKR	165 MW_{el} Steinkohle	Thyssen Engineering Kalkwäsche (Thyssen-Mitsubishi)	100 %	Gips Baustoffindustrie	Baubeginn 4. Q. 1985 Inbetriebnahme 4. Q. 1987
Ibbenbüren RWE/Preussag	770 MW_{el} Steinkohle	Thyssen Engineering Kalkwäsche (Thyssen-Mitsubishi)	33 %	Gips Baustoffindustrie	Im Bau Inbetriebnahme 1985
		Thyssen Engineering Kalkwäsche (Thyssen-Mitsubishi)	2 x 33 %	Gips Baustoffindustrie	Baubeginn 1985 Inbetriebnahme 1988
Frimmersdorf RWE	2 x 300 MW_{el} Braunkohle	Thyssen Engineering Kalksteinwäsche (Thyssen-Mitsubishi)	2 x 100 %	Gips Baustoffindustrie oder Deponie	Baubeginn Ende 1985 Inbetriebnahme Anfang 1988
Kraftwerk Arzberg Energieversorgung Oberfranken	230 MW_{el} Braunkohle	Uhde Absorption mit Aktivkoks 1) (Bergbau-Forschung)	100 %	Schwefelsäure Weiterverarbeitung	Baubeginn 1985 2) Inbetriebnahme Oktober 1986
Großkraftwerk Mannheim, Block 7 Großkraftwerk Mannheim	475 MW_{el} Steinkohle	Walther Ammoniakwäsche	50 %	Ammoniumsulfat Düngemittel	seit 1983 in Betrieb
Großkraftwerk Mannheim Blöcke 14 und 15 Großkraftwerk Mannheim	440 MW_{el} Steinkohle	Walther Ammoniakwäsche 1)	100 %	Ammoniumsulfat-salpeter Düngemittel	Baubeginn September 1985 Inbetriebnahme Mai 1987
HKW West, Karlsruhe Stadtwerke Karlsruhe	191 MW_{th} Steinkohle	Walther Ammoniakwäsche	100 %	Ammoniumsulfat-salpeter Düngemittel	Baubeginn Juli 1985 Inbetriebnahme Sept. 1986
HKW Haferweg HEW	120 MW_{el} + 300 MW_{th} Steinkohle	Walther Ammoniakwäsche	100 %	Ammoniumsulfat-salpeter Düngemittel	Baubeginn Juni 1986 Inbetriebnahme April 1988

1) kombinierte Entschwefelung und Entstickung   2) Konstruktionsauftrag ■

Analysis of a 1986 Acid Rain Control Proposal in Response to Congressman Henry Waxman

Staff Paper

prepared by the

OTA Oceans and Environment Program

April 9, 1986

The views expressed in this Staff Paper do not necessarily represent the views of the Technology Assessment Board, the Technology Assessment Advisory Council or individual members thereof.

I. Introduction

The Office of Technology Assessment was asked by Congressman Waxman, Chairman of the House Subcommittee on Health and the Environment, to analyze the emissions reductions achieved by, and costs of, an acid rain control proposal being considered by the several Members of the Subcommittee. Our interpretation of the control proposal is from a preliminary draft of the bill and discussions with Subcommittee staff. The quantitative analysis is based on data and models used for OTA's June 1984 assessment, "Acid Rain and Transported Air Pollutants: Implications for Public Policy".

II. Control Requirements

As we understand the proposal, the major emissions control provisions include:

- Sulfur dioxide emissions from utility boilers:
  1) By 1993, no State can exceed a monthly average sulfur dioxide emission rate of 2.0 lbs/ million Btu heat input from all fossil-fuel-fired utility sources.
  2) By 1997, no State can exceed a monthly average sulfur dioxide emission rate of 1.2 lbs/ million Btu heat input from these same sources.

- Nitrogen oxide emissions from utility boilers:

1) By 1997, no State can exceed a monthly average nitrogen oxides emission rate of 0.6 lbs/ million Btu heat input from all fossil-fuel-fired utility sources.

deleted

2) New Source Performance Standards (NSPS) for nitrogen oxides are lowered to 0.3 lbs/ million Btu for utility boilers burning subbituminous coal and 0.4 lbs/ million Btu for utility boilers burning bituminous coal.

o Sulfur dioxide and nitrogen oxide emissions from nonutility boilers:

1) By 1997, no State can exceed a monthly average sulfur dioxide emission rate of 1.2 lbs/ million Btu heat input from fossil-fuel-fired nonutility boilers.

2) By 1997, no State can exceed a monthly average nitrogen oxide emission rate of 0.6 lbs/ million Btu heat input from fossil-fuel-fired nonutility boilers.

o Industrial process emissions of sulfur and nitrogen oxides:

1) By 1997, each State shall reduce industrial process emissions of sulfur and nitrogen oxides to the extent that is "economically and technically achievable" as determined by the Administrator of EPA.

2) The proposal requires that nonferrous smelters be in compliance with their applicable implementation plan by 1988.

o Mobile source emissions:

The proposal includes new standards for nitrogen oxides and hydrocarbons emissions from mobile sources, and establishes a limit on the sulfur content allowed in motor vehicle diesel fuel.

At this time, we have reviewed only the nitrogen oxides provisions. The truck and heavy duty vehicle standards are identical to those already promulgated for future years by EPA. The nitrogen oxides standard for passenger cars is lowered to 0.7 grams per mile for 1989 and later.

III. Other Provisions in the Draft Bill

These include:

o Interest subsidy program:

The Administrator of EPA is authorized to subsidize some pollution control costs if residential electricity rates increase by more than 10 percent due to the installation of emissions control technology. The Administrator can subsidize only interest costs on debt from the purchase of continuous emissions control technology for removal of sulfur and nitrogen oxides. The cost of operating and maintaining the control technology, or the increased cost of switching to lower-polluting fuels, cannot be subsidized. The provision does not apply to new utility sources.

Funds to pay for the subsidies are raised from a fee on electricity generated or imported. The fee takes effect by 1989 and must expire before 1997. The amount of the fee is set by the Administrator, but must not exceed 0.5 mills per kilowatt-hour.

o Mid-term review of control requirements:

The major stationary-source emissions control requirements are grouped into two phases: an initial reduction of sulfur dioxide emissions by 1993, with the remainder of emissions controls scheduled for 1997. Congress is to review the second-phase control requirements by 1994, after receiving a report from the Administrator of EPA describing the effectiveness of the initial reductions and the feasibility of meeting ~~the~~ second-phase emissions reductions. The requirements remain in effect unless repealed by law.

IV. Emissions Reductions

A. Sulfur Dioxide from Utilities

If the proposal becomes law, we estimate that first-phase control requirements would reduce utility sulfur dioxide emissions by about 5 million to 6 million tons below projected 1993 levels. The second-phase requirements would reduce utility sulfur dioxide emissions by about 10 million tons below 1997 levels.

Future emissions levels, however, are projected to be higher than current emissions if current laws and energy use patterns remain about the same as today. Compared to current utility emissions of about 17 million tons per year, the proposal might result in lowering sulfur dioxide emissions by about 4 million to 5 million tons per year by 1993 and about 8 million to 9 million tons per year by 1997.[1]

Estimates of emissions reductions to achieve the 1993 and 1997 emission rate limitations by State are presented in table 1 and table 2, respectively.

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[1] Future emissions growth is based on estimates presented in our 1984 report, cited earlier, and a April 12, 1985 memorandum to EPA from ICF Inc. ,"EPA Base Case Forecasts".

These estimates have been calculated by applying the control requirements (as described above) to the 1980 emissions inventory. Actual reductions might be somewhat higher or lower, depending on whether increased demand for electricity will be met by increased use of older, higher-emitting plants or from new utilities subject to New Source Performance Standards. The newer sources would lower Statewide-average emission rates, thereby lowering State emissions reduction requirements.

We have calculated emission rates in the following manner, after discussions with Subcommittee staff: We assume that in order to meet a specified monthly emission rate, each plant will have to operate at a rate slightly lower than the final annual average. For example, in order to stay below 1.2 lbs/ million Btu in all months, a plant would average about 1.0 lbs/ million Btu over a year. We have calculated monthly, statewide-average emission rates as the arithmetic average of all of these lower plant averages.[2] If our averaging assumptions are incorrect, emissions reductions could be about 1 million tons lower than stated above.

B. Nitrogen Oxides from Utilities

We estimate that the proposal would reduce nitrogen oxides emissions from existing utility sources by about 2 million to 2.5 million tons per year by 1997. For comparison, utility nitrogen oxides emissions during 1980 were about 7 million tons.

Our calculation procedures are similar to those described above for utility sulfur dioxide emissions reductions. We have not yet estimated the lowered emissions from revisions to New Source Performance Standards for new coal-fired utilities.

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[2] The formula that we use is: the sum of the quantity of fuel burned by each plant multiplied by the monthly emission rate of that plant, divided by the fuel burned within the entire State.

C. Emissions from Nonutility Boilers

We estimate that the proposal would reduce sulfur dioxide emissions from nonutility boilers by about 0.5 million tons per year. For comparison, 1980 sulfur dioxide emissions from this sector were about 3.5 million tons. Because nonutility boilers in most States currently emit nitrogen oxides at a lower rate than that specified in the proposal, we do not expect significant nitrogen oxide reductions.

Because emissions from this sector are not as accurately characterized as utility emissions, our confidence in these estimates is not high.

D. Industrial Process Emissions

The proposal mandates industrial process-emissions reductions to the extent that is economically achievable, as defined by the EPA Administrator. If the Administrator chooses $1000 per ton of sulfur dioxide removed as the appropriate cutoff, we estimate that about 0.3 million to 0.4 million tons of sulfur dioxide might be eliminated from coke ovens, sulfur manufacturers, sulfuric acid producers, and other assorted industrial emitters. At $2000 per ton of sulfur dioxide removed, an additional 0.5 million tons might be eliminated from cement plants, petroleum refineries, and other industrial sources.[3]

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[3] Estimates of industrial process emissions and control costs are based on data from: E. H. Pechan and Associates, 1984, "BACT/LAER Control Techniques and Costs for Industrial SO2 Sources", report to OTA, August 1984; and our June 1984 report, cited earlier.

For comparison, 1980 sulfur dioxide emissions were between 4 million and 5 million tons per year, with about 1.3 million tons from nonferrous smelters. We have assumed that by the 1997 deadline, nonferrous smelters will already have substantially reduced sulfur dioxide emissions, even without such a law. Thus we did not estimate potential emissions reductions from these sources.

We do not have the data we need to estimate reductions of nitrogen oxides from industrial process emitters. Emissions during 1980 were roughly 1 million tons per year.

E. Nitrogen Oxides from Mobile Sources

We estimate that lowering the passenger car emission rate to 0.7 grams nitrogen oxides per mile will reduce 1997 emissions by about 0.3 million tons per year. Substantial reductions would also be achieved by lowering the truck standards from their current rates, but since these changes have already been promulgated by EPA, we did not include the effect of this portion of the proposal.

V. Costs of Control

The only costs that we have estimated at this time are for sulfur dioxide control.

If the proposal is enacted into law, utility control costs during the second phase of the control program would be about $3.4 billion to $4.3 billion per year. We estimate that this would result in a nationwide-average electricity rate increase for typical residential consumers of about 2 percent to 3 percent. This would vary by State and utility service district, of course, with consumers in some States paying no increase other than the electricity generation fee (less than 1 percent, for several years before 1997) and consumers in other states paying several times the national average (10 percent or more in the hardest hit areas). Estimates of State-average electricity rate increases, not including the effects of the control technology subsidies allowed by the proposal, are shown in table 3 and figures 1 and 2.

We estimate that controlling nonutility boilers will cost about $0.2 billion to $0.3 billion per year. A very crude estimate of the cost of controlling industrial process emissions, assuming a cutoff of $1000 per ton of sulfur dioxide removed, is about one-quarter billion dollars per year.

VI. Summary

If all the sulfur dioxide control requirements of the proposal are enacted into law, we estimate that control costs would be about $3.8 billion to $4.9 billion per year and sulfur dioxide emissions would be reduced by about 10.5 to 11 million tons per year below 1997 levels. After accounting for future increases in electricity and industrial production, we estimate that 1997 sulfur dioxide emissions will be about 9 million to 10 million tons lower than 1980 emissions.

Nitrogen oxides emissions reductions from utility boilers and passenger cars would be about 2 million tons per year by 1997.

Table 1. Sulfur Dioxide Emission Reductions to meet 2.0 lbs/million Btu, Statewide monthly average

STATE:	SO2 EMISSIONS: (thousand tons/year) 1980 total	1980 utility	EMISSION REDUCTIONS: 2.0 lb/mmBtu 30-day avg. thousand tons/year	% of total	% of utility
ALABAMA	759	543	118	16%	22%
ARIZONA	900	88	0	0%	0%
ARKANSAS	102	27	10	9%	36%
CALIFORNIA	446	78	0	0%	0%
COLORADO	132	78	0	0%	0%
CONNECTICUT	72	32	0	0%	1%
DELAWARE	109	53	23	21%	44%
DC	15	5	0	0%	0%
FLORIDA	1095	726	1	0%	0%
GEORGIA	840	737	279	33%	38%
IDAHO	47	0	0	0%	0%
ILLINOIS	1471	1126	375	26%	33%
INDIANA	2008	1540	880	44%	57%
IOWA	329	231	42	13%	18%
KANSAS	223	150	23	10%	15%
KENTUCKY	1121	1008	504	45%	50%
LOUISIANA	304	25	0	0%	0%
MAINE	95	16	0	0%	0%
MARYLAND	338	223	32	9%	14%
MASSACHUSETTS	344	276	57	16%	21%
MICHIGAN	907	565	3	0%	0%
MINNESOTA	260	177	0	0%	0%
MISSISSIPPI	285	129	0	0%	0%
MISSOURI	1301	1141	684	53%	60%
MONTANA	164	23	0	0%	0%
NEBRASKA	75	49	0	0%	0%
NEVADA	243	40	0	0%	0%
NEW HAMPSHIRE	93	81	31	33%	38%
NEW JERSEY	279	110	0	0%	0%
NEW MEXICO	269	85	19	7%	22%
NEW YORK	944	480	5	1%	1%
NORTH CAROLINA	602	435	0	0%	0%
NORTH DAKOTA	107	83	0	0%	0%
OHIO	2647	2172	1143	43%	53%
OKLAHOMA	121	38	0	0%	0%
OREGON	60	3	0	0%	0%
PENNSYLVANIA	2022	1466	411	20%	28%
RHODE ISLAND	15	5	0	0%	0%
SOUTH CAROLINA	326	213	11	3%	5%
SOUTH DAKOTA	39	29	0	0%	0%
TENNESSEE	1077	934	479	45%	51%
TEXAS	1277	303	0	0%	0%
UTAH	72	23	0	0%	0%
VERMONT	7	1	0	0%	0%
VIRGINIA	361	164	4	1%	3%
WASHINGTON	272	69	27	10%	39%
WEST VIRGINIA	1088	944	315	29%	33%
WISCONSIN	637	486	229	36%	47%
WYOMING	184	121	50	27%	41%
NATIONAL TOTALS	26480	17325	5753	22%	33%

Table 2. Sulfur Dioxide Emission Reductions to meet 1.2 lbs/million Btu, Statewide monthly average

STATE:	SO2 EMISSIONS: (thousand tons/year) 1980 total	1980 utility	EMISSION REDUCTIONS: 1.2 lb/mmBtu 30-day avg. thousand tons/year	% of total	% of utility
ALABAMA	759	543	307	40%	57%
ARIZONA	900	88	0	0%	0%
ARKANSAS	102	27	10	9%	36%
CALIFORNIA	446	78	0	0%	0%
COLORADO	132	78	0	0%	0%
CONNECTICUT	72	32	0	0%	1%
DELAWARE	109	53	23	21%	44%
DC	15	5	0	0%	0%
FLORIDA	1095	726	299	27%	41%
GEORGIA	840	737	480	57%	65%
IDAHO	47	0	0	0%	0%
ILLINOIS	1471	1126	709	48%	63%
INDIANA	2008	1540	1173	58%	76%
IOWA	329	231	126	38%	55%
KANSAS	223	150	23	10%	15%
KENTUCKY	1121	1008	726	65%	72%
LOUISIANA	304	25	0	0%	0%
MAINE	95	16	1	1%	6%
MARYLAND	338	223	117	35%	52%
MASSACHUSETTS	344	276	120	35%	44%
MICHIGAN	907	565	251	28%	44%
MINNESOTA	260	177	59	23%	33%
MISSISSIPPI	285	129	30	10%	23%
MISSOURI	1301	1141	887	68%	78%
MONTANA	164	23	0	0%	0%
NEBRASKA	75	49	0	0%	0%
NEVADA	243	40	0	0%	0%
NEW HAMPSHIRE	93	81	52	56%	65%
NEW JERSEY	279	110	0	0%	0%
NEW MEXICO	269	85	19	7%	22%
NEW YORK	944	480	137	15%	29%
NORTH CAROLINA	602	435	139	23%	32%
NORTH DAKOTA	107	83	14	13%	17%
OHIO	2647	2172	1600	60%	74%
OKLAHOMA	121	38	0	0%	0%
OREGON	60	3	0	0%	0%
PENNSYLVANIA	2022	1466	880	44%	60%
RHODE ISLAND	15	5	0	0%	0%
SOUTH CAROLINA	326	213	101	31%	47%
SOUTH DAKOTA	39	29	12	29%	40%
TENNESSEE	1077	934	681	63%	73%
TEXAS	1277	303	0	0%	0%
UTAH	72	23	0	0%	0%
VERMONT	7	1	0	1%	17%
VIRGINIA	361	164	45	12%	27%
WASHINGTON	272	69	29	10%	41%
WEST VIRGINIA	1088	944	594	55%	63%
WISCONSIN	637	486	343	54%	71%
WYOMING	184	121	50	27%	41%
NATIONAL TOTALS	26480	17325	10035.5	38%	58%

Table 3. State Average Electric Rate Increases
For a Typical Residential Consumer

STATE:	PERCENT INCREASE:
ALABAMA	2% to 4%
ARIZONA	0% to 0%
ARKANSAS	0% to 0%
CALIFORNIA	0% to 0%
COLORADO	0% to 0%
CONNECTICUT	0% to 0%
DELAWARE	0% to 0%
DC	0% to 0%
FLORIDA	1% to 2%
GEORGIA	6% to 8%
IDAHO	0% to 0%
ILLINOIS	3% to 3%
INDIANA	11% to 11%
IOWA	3% to 6%
KANSAS	0% to 0%
KENTUCKY	12% to 14%
LOUISIANA	0% to 0%
MAINE	0% to 0%
MARYLAND	3% to 4%
MASSACHUSETTS	2% to 2%
MICHIGAN	2% to 3%
MINNESOTA	1% to 3%
MISSISSIPPI	0% to 1%
MISSOURI	4% to 4%
MONTANA	0% to 0%
NEBRASKA	0% to 0%
NEVADA	0% to 0%
NEW HAMPSHIRE	6% to 6%
NEW JERSEY	0% to 0%
NEW MEXICO	0% to 0%
NEW YORK	1% to 1%
NORTH CAROLINA	1% to 3%
NORTH DAKOTA	2% to 4%
OHIO	7% to 7%
OKLAHOMA	0% to 0%
OREGON	0% to 0%
PENNSYLVANIA	5% to 5%
RHODE ISLAND	0% to 0%
SOUTH CAROLINA	2% to 3%
SOUTH DAKOTA	0% to 1%
TENNESSEE	3% to 5%
TEXAS	0% to 0%
UTAH	0% to 0%
VERMONT	0% to 0%
VIRGINIA	1% to 1%
WASHINGTON	0% to 0%
WEST VIRGINIA	9% to 13%
WISCONSIN	2% to 5%
WYOMING	0% to 0%
NATIONAL TOTALS	2% to 3%

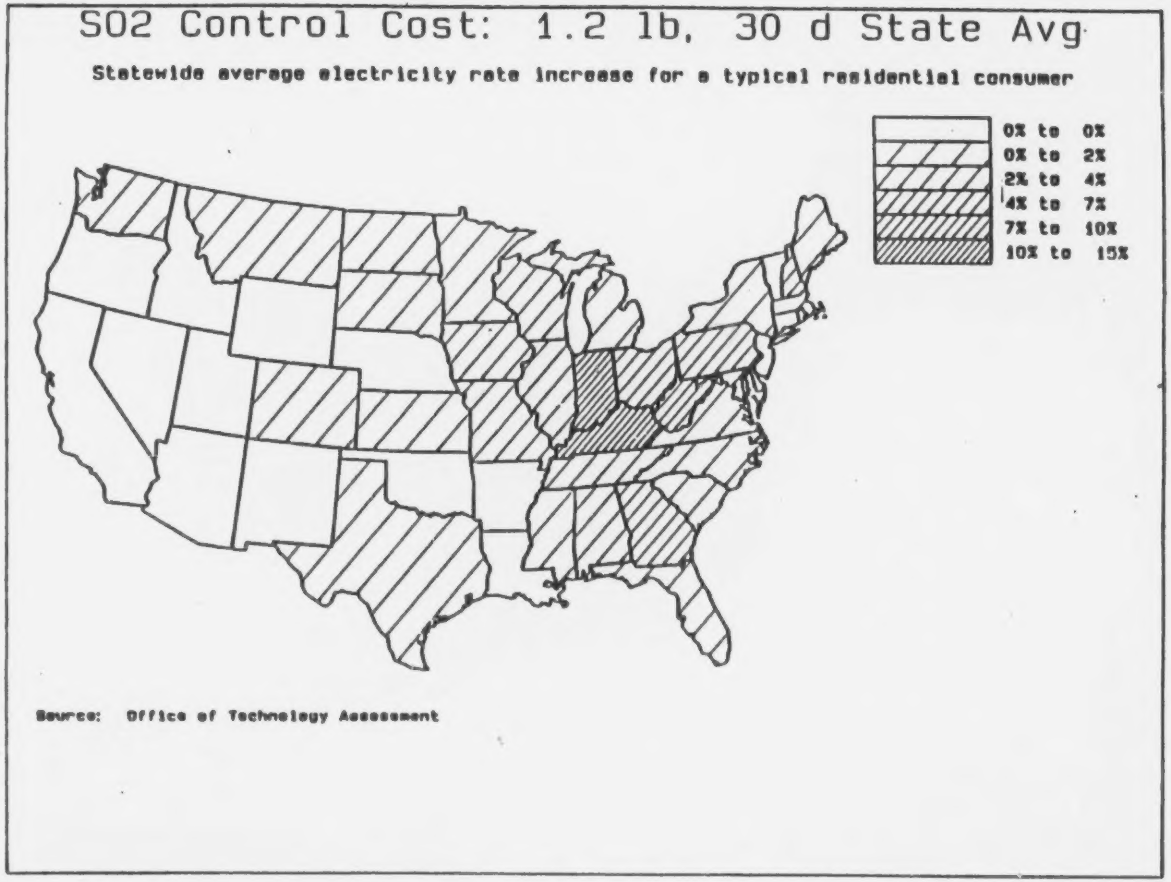
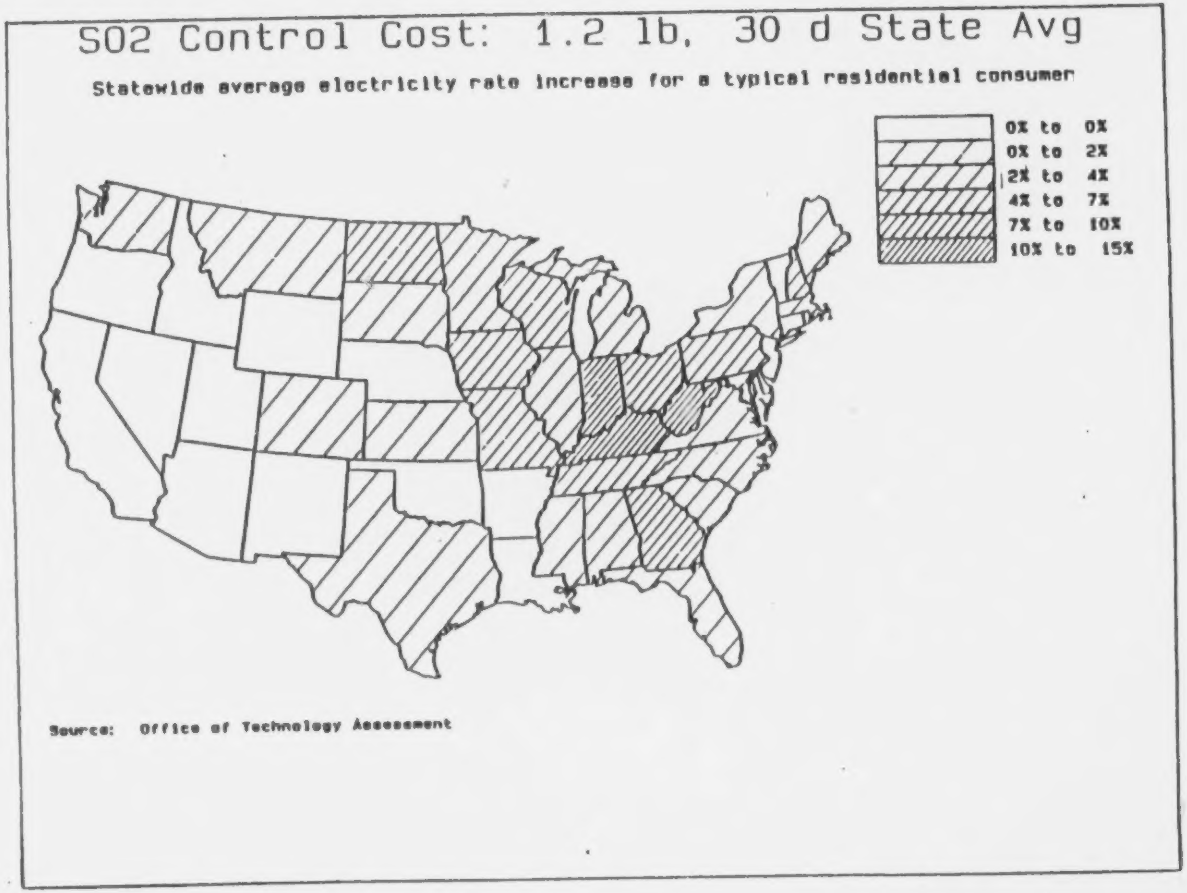

SO2 Control Cost: 1.2 lb, 30 d State Avg
Statewide average electricity rate increase for a typical residential consumer
0% to 0%
0% to 2%
2% to 4%
4% to 7%
7% to 10%
10% to 15%
Source: Office of Technology Assessment

Figure 1. Lower-bound Control Cost Estimate


SO2 Control Cost: 1.2 lb, 30 d State Avg
Statewide average electricity rate increase for a typical residential consumer
0% to 0%
0% to 2%
2% to 4%
4% to 7%
7% to 10%
10% to 15%

Source: Office of Technology Assessment

Figure 2. Upper-bound Control Cost Estimate

EDISON ELECTRIC
INSTITUTE

Economic Evaluation of H.R. 4567

The "Acid Deposition Control Act of 1986"

prepared by

TEMPLE, BARKER & SLOANE, INC.

April 14, 1986

EDISON ELECTRIC INSTITUTE

Economic Evaluation of H.R. 4567

The "Acid Deposition Control Act of 1986"

—

prepared for

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April 14, 1986

HIGHLIGHTS

• SO_2 Reduction	8.3 million tons from 1983-1985 levels at historical operating rates + offsets of future increases to serve growth
• Annual Cost	$9.2 billion per year for first five years of full compliance, 1997-2001 (in 1986 dollars) Equivalent to $5.4 billion per year annually for each of the next 20 years, through 2007 (in 1986 dollars)
• Cumulative Cost Through First 15 Years of Compliance	$110 billion in 1986 dollars (1993-2007) versus $86 billion for HR3400 (1990-2004)
• Average Rate Increase	Over 10 percent average rate increases at 30 major utility companies
• Coal Switching	116 million tons of annual coal usage switched to compliance ("low sulfur") coal
• Cost Sharing Fund	Would provide no rate relief to customers, since pollution control debt financing alone would not cause residential rates to rise over 10 percent at any utility

HR4567 WOULD BE MORE EXPENSIVE THAN 1983 "SIKORSKI/WAXMAN" BILL
(HR3400 IN 98TH CONGRESS)

	New HR4567	Former HR3400
● Total costs would be higher (in 1986 dollars)		
--Average annual cost for first five years at full compliance	$ 9.2b	$ 6.2b
--Cumulative cost through 15 years of full compliance	110b	86b

- Customer rate increases may appear even more sharply increased due to reporting by individual utility company instead of by statewide averages.

- Reasons for the increase:

  --Added financing costs in the capital markets because utilities will not qualify for assistance from the cost-sharing fund and will pay about $1.2 billion per year for financing

  --Added NOX emission requirements which cost about $0.4 billion per year

  --Added cost for compliance efforts at some older units that would have been retired under HR3400's requirement to scrub at the "Top 50" powerplants

  --Added cost for many current users of low sulfur coal whose contracts will expire in the late 1980s or early 1990s and would be affected by changes in market prices and transportation rates--almost $1 billion per year

- And there are no significant "savings" in HR4567.

  --Scrubbing would still be widely used because the 1997 emission limitation is stringent--estimated 74 Gw would scrub under this bill versus 86 Gw for HR3400.

  --Low sulfur coal prices and related transportation cots would, if anything, be higher under this bill since even more coal switching would occur.

INTRODUCTION

A new bill for acid rain control was introduced in the U.S. House of Representatives on April 10, 1986. It seeks to reduce:

- Sulfur dioxide and nitrogen emissions from:

  --Electric utilities
  --Industrial boilers
  --Industrial process emissions

- Nitrogen oxide and hydrocarbon emissions from motor vehicles, and
- Sulfur in motor vehicle diesel fuel

This analysis is focused on identifying the costs of this proposed program on the electric utility industry and its customers, specifically:

- How would utilities be likely to comply with it?
- How much would it cost?
- How would those costs be distributed across states and individual utility companies?
- How much would customer rates increase?
- How effective would the cost sharing provisions of the bill be?

REQUIREMENTS OF THE BILL FOR ELECTRIC UTILITIES

- SO_2 Emission requirements from all fossil-fuel fired electric utility steam generating units

  --By 1993, average monthly statewide emissions of 2.0 LBS/MMBTU

  --By 1997, average monthly statewide emissions of 1.2 LBS/MMBTU

- NOX Emission requirements from all fossil fuel-fired electric utility steam generating units

  --By 1997, average monthly statewide emissions of 0.6 LBS/MMBTU

  --New source performance standard revision to 0.30 LBS/MMBTU for subbituninous coal

  --New source performance standard revision to 0.40 LBS/MMBTU for bituminous coal

- "Acid Deposition Control Fund"

  --Interest subsidy on qualified pollution control debt

  --"To ensure that no residential customer rate payment will exceed by more than 10 percent the rate payment which would have been required if no qualified pollution control debt has been incurred by the utility."

  --Fee on generation or importation of electric energy of up to 1/2 mill per kWH from 1/1/89 through 12/31/96

TBS METHODOLOGY

5 MAJOR STEPS

1. Analyze all 1,125 operating coal-fired electric utility generating units in the U.S., in terms of age, emission rate, size, capacity factor, and relative importance to its utility company

2. Develop representative compliance strategies for each of 216 utility companies to meet the proposed emission limits, based on decision rules reflecting how most utilities would make such decisions

3. Develop yearly estimates for 1986-2017 of capital, operating and other expenses for each of 120 major utility companies and, in aggregate, for the smaller utilities in each state

4. Calculate average customer rate increases for the major utility companies and for state averages

5. Summarize results at key levels -- 120 individual electric utility companies, 48 states, and national totals

KEY OPERATING DATA & ASSUMPTIONS

- SO_2 Emissions Data

  --1980 through 1983 data from EEI's Power Statistics Database
  --1984 and 1985 data from National Coal Association

- SO_2 Emission Reductions

  --Mandated statewide averages for emission rates assumed to also apply to each utility company
  --Complete trading allowed among units to achieve the target average emission rate for each utility company
  --Monthly averages assumed to be approximately 10 percent stricter than annual averages (e.g., 1.2 lbs/MMbTU monthly average is approximately equivalent to 1.1 lbs/MMbTU on an annual basis)

- SO_2 Compliance Strategies

  --Based on 1983 to 1985 actual emission rates
  --Decision rules for coal-fired--switch to compliance coal first, scrub next, and retire units only if necessary--based on each units emission rate, age, capacity factor, and relative importance to the utility system
  --Oil and gas-fired units assumed in compliance

- NOX Controls

  --Emission data not generally available
  --Assumed 75% of coal units could comply with burner modifications, and 25% could comply with present equipment through changes in operating procedures, if necessary

- Generating unit operating characteristics assumed to remain at historical levels--heat rate, sulfur content and heat content of fuel, and capacity factor

KEY FINANCIAL ASSUMPTIONS
(1986 dollars)

- Scrubber Costs

  --$280 per kw capital cost
  --$13 per kw annual fixed O&M
  --1.7 mills per kwh for variable O&M
  --5.5% energy and capacity penalty

- Low Sulfur coal average delivered price differential (for compliance coal vs. coal at 3.0 lbs/MMbTU or higher), this includes market ability to charge excess "economic rents", differentials in mine productivity, and transportation cost differences

  --$3 to $6 per ton for less than 40 million tons of switching nationwide
  --$10 to $12 per ton at 75 to 100 million tons
  --Flattening out at $15 to $20 per ton at 150 million tons of switching, limited by the cost of scrubbing and by the delivered cost differential for Powder River Basin coal

- Effect on Current Low Sulfur Coal Users

  --On average, approximately half of the price differential for new coal switching would also effect current low sulfur coal users, through contract reopeners and re-negotiation of the large proportion of contracts that expire in the late 1980's and early 1990's; current Western low sulfur coal users would experience less of an impact, perhaps only 15-20 percent of the differential for new Western coal contracts

- NOX Controls--$10 per kw for burner modifications

- Costs stated in 1986 dollars

CAVEATS

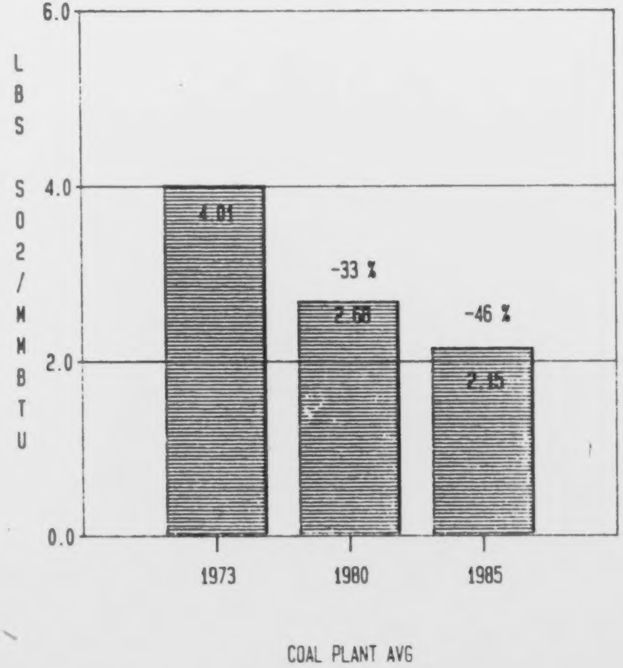
- Representativeness - The results for individual utility companies are representative estimates, based on industry-wide data on compliance costs and decision-making; the exact compliance methods and costs for specific utility companies may be higher or lower depending upon corporate decisions and local circumstances

- Future changes in utility loads - These cost estimates are conservatively low because they are based on historical capacity factors and do not include increased compliance costs for plants that will operate at higher rates to serve future increases in demand

- Uncertainty - The greatest area of uncertainty in these cost estimates is in the relative prices of low sulfur and higher sulfur coal. Some utility companies expect the price differential would be significantly higher than used here, while some economists and coal companies expect it could be lower. A difference of $5 per ton in the price differential, with the same volume of coal switching, would result in a change in the total annual cost of this program of approximately $0.9 billion in 1986 dollars.

NATIONAL EMISSION RATE TRENDS AT COAL-FIRED UTILITY PLANTS

PAST 15 YEARS UNDER
THE CLEAN AIR ACT



FUTURE TRENDS

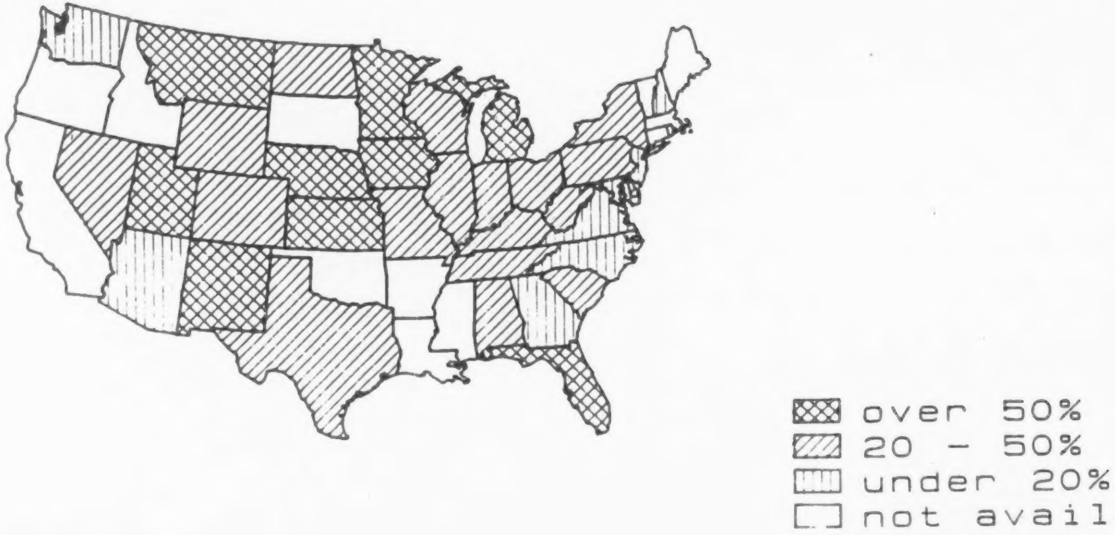
CONTINUING DECLINES

- o FURTHER REDUCTIONS UNDER SIPs IN SELECTED STATES
- o NSPS PLANTS COMING ON LINE AT 1.2 AND 0.6 LB EMISSION RATES
- o IF ECONOMIC GROWTH IN THE WEST AND OTHER LOW EMISSION RATE REGIONS CONTINUES TO OUTPACE THE MIDWEST

AND SOME INCREASES

- o INCREASING UTILIZATION AT EXISTING PLANTS AS DEMAND GROWS
- o IF ECONOMIC GROWTH IN THE MIDWEST EXCEEDS THE RATE IN THE WEST AND OTHER LOW EMISSION RATE AREAS

% Reductions in State Average
SO2 Emission Rates per MMBtu
1973 to 1985



10.

REQUIRED ADDITIONAL SO_2 REDUCTION FROM COAL-FIRED UTILITY PLANTS TO MEET HR4567 REQUIREMENTS

(million tons per year)

State	1983/85* Emissions	Required Reduction 1993	Required Reduction 1997	% by 1997
Alabama	.43	.07	.21	49%
Arkansas	.07	--	--	--
Arizona	.09	--	--	--
Colorado	.08	--	--	--
Delaware	.06	--	.02	31
Florida	.71	.34	.49	69
Georgia	.82	.33	.52	64
Iowa	.17	.04	.06	37
Illinois	1.08	.45	.69	64
Indiana	1.48	.80	1.07	72
Kansas	.08	.01	.02	21
Kentucky	.57	.13	.29	50
Louisiana	.03	--	--	--
Massachusetts	.08	.00	.02	36
Maryland	.19	.04	.10	54
Michigan	.40	.01	.09	24
Minnesota	.13	.01	.02	17
Missouri	1.04	.58	.76	73
Mississippi	.08	.02	.04	50
Montana	.02	.00	.00	22
North Carolina	.37	--	.08	20
North Dakota	.10	.00	.02	21
Nebraska	.04	--	--	--
New Hampshire	.05	.03	.03	70
New Jersey	.09	.02	.05	53
New Mexico	.04	--	--	--
Nevada	.04	--	--	--
New York	.23	.08	.14	60
Ohio	2.02	1.07	1.44	71
Oklahoma	.09	--	.00	1
Oregon	.00	--	--	--
Pennsylvania	1.17	.36	.66	57
South Carolina	.17	.02	.06	36
South Dakota	.04	.01	.02	56
Tennessee	.75	.33	.50	67
Texas	.40	--	.02	5
Utah	.02	--	--	--
Virginia	.12	--	.00	1
Washington	.07	.01	.03	48
Wisconsin	.47	.19	.30	64
West Virginia	.90	.31	.50	56
Wyoming	.10	--	--	--
Total	14.87	5.28	8.28	56%

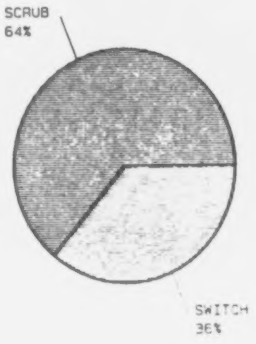
---

*1983 data adjusted for major fuel changes and new scrubbers at existing units in 1984 and 1985.

Note "--" indicates no reduction required.

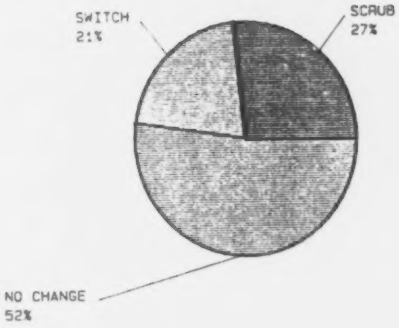
PROJECTED 1997 COMPLIANCE METHODS
NATIONAL SUMMARY

SO2 REDUCTIONS
BY COMPLIANCE METHOD



	SO2 REDUCTION
SCRUB	5.3 mm Tons
SWITCH TO LOW SULFUR COAL	3.0 mm Tons
TOTAL	8.3 mm Tons

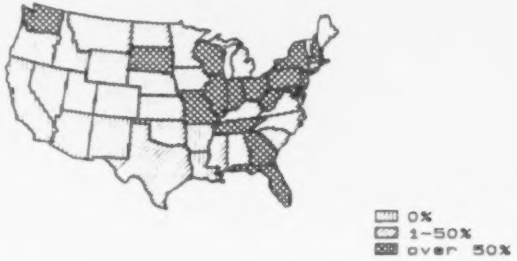
COAL FIRED CAPACITY
BY COMPLIANCE METHOD

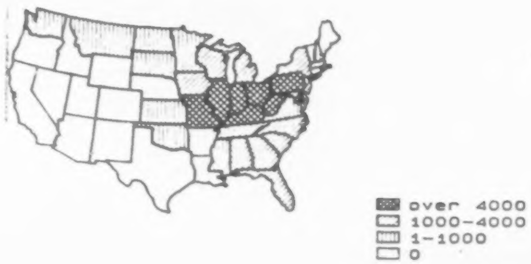


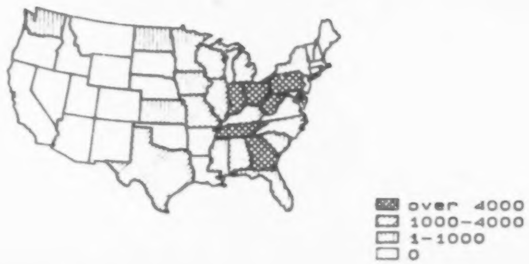
	COAL CAPACITY
SCRUB	74 GW
SWITCH TO LOW SULFUR COAL	59 GW
NO CHANGE	145 GW
TOTAL	278 GW

PROJECTED COMPLIANCE STRATEGIES BY STATE - 1997

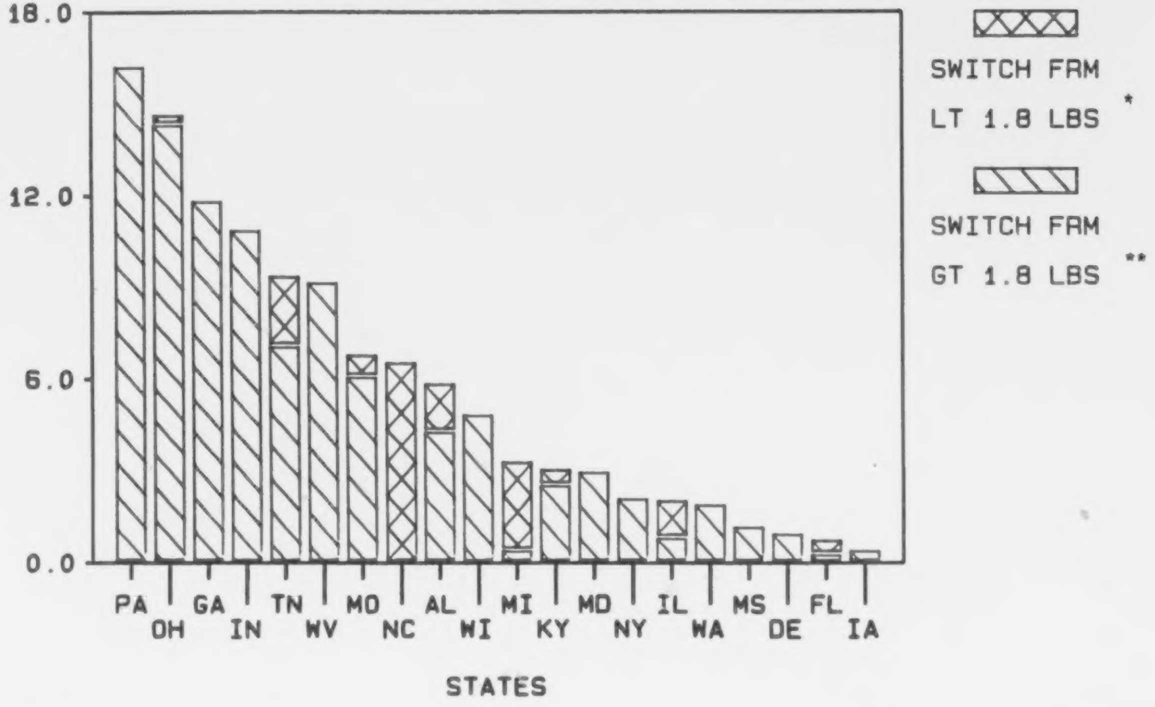
- 17 STATES WOULD HAVE TO SCRUB OR SWITCH HALF THEIR COAL CAPACITY
- 7 STATES WOULD SCRUB OVER 4000 MW EACH
- 6 STATES WOULD SWITCH OVER 4000 MW EACH


Percent Coal Megawatts Impacted Estimated to Scrub or Switch


Coal Megawatts Scrubbed by State


Coal Megawatts Switched by State

COAL TONNAGE AFFECTED
1997 Changes in Coal Purchases by State

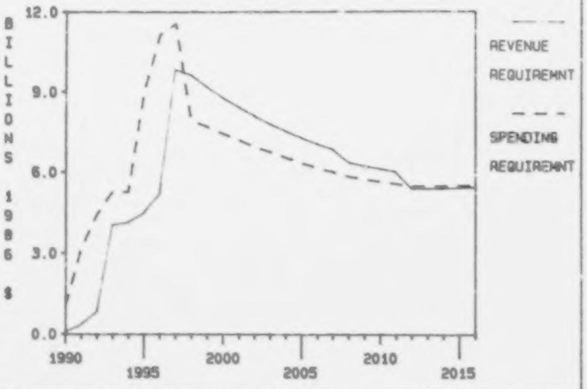


*Less than 1.8 lbs/mmBTU
**Greater than 1.8 lbs/mmBTU

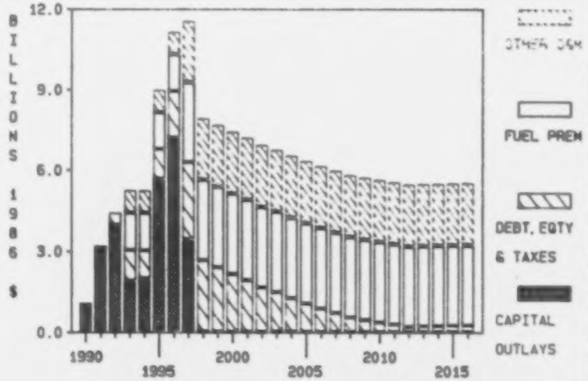
NATIONAL SUMMARY OF COSTS (1986 DOLLARS)

Annual average revenue requirements--first 5 years of full compliance, 1997-2001	
Financing and depreciation	$ 3.0 billion
Net taxes	0.9
Low sulfur fuel cost differential	3.0
Other operating and maintenance	2.3
Total	$ 9.2 billion
Capital expenditures, excluding replacement capacity	
Scrubbers	$ 22.0 billion
Low sulfur coal switching	4.1
NOX control	2.2
Total	$ 28.3 billion
Net present value, revenue requirements for 30 years, 1987-2016	$ 69 billion
Cumulative revenue requirements in 1986 dollars, through first 15 years of compliance--approximately the next twenty years (through 2007)	$110 billion

ESTIMATED UTILITY IMPACT FROM H.R. 4567
SPENDING VS REVENUE REQUIREMENTS

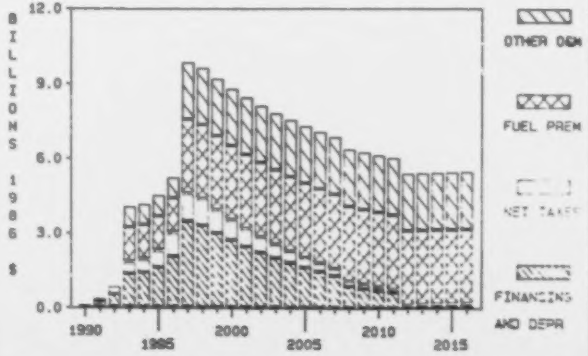


ESTIMATED UTILITY IMPACT FROM H.R. 4567
NATIONAL UTILITY SPENDING REQUIREMENTS

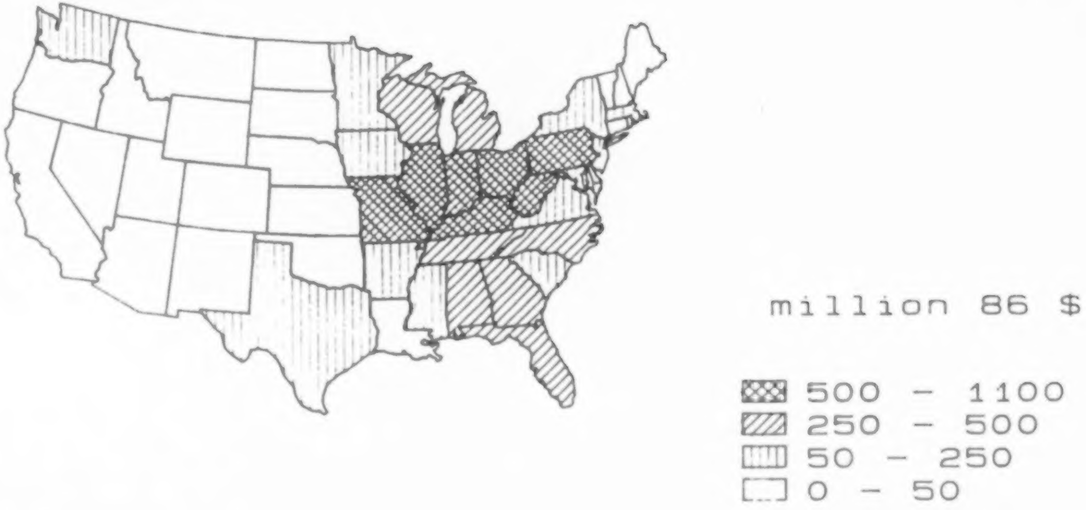


THE FIGURES ILLUSTRATED ON THIS CHART ARE ALL PRESENTED IN CONSTANT 1986 DOLLARS. THIS MEANS THAT THE EFFECTS OF INFLATION ARE NOT INCLUDED IN EACH DOLLAR ESTIMATE. THE SPENDING AND REVENUE REQUIREMENTS REPRESENT THE EQUIVALENT OF PAYING FOR FUTURE COSTS WITH TODAY'S DOLLARS.

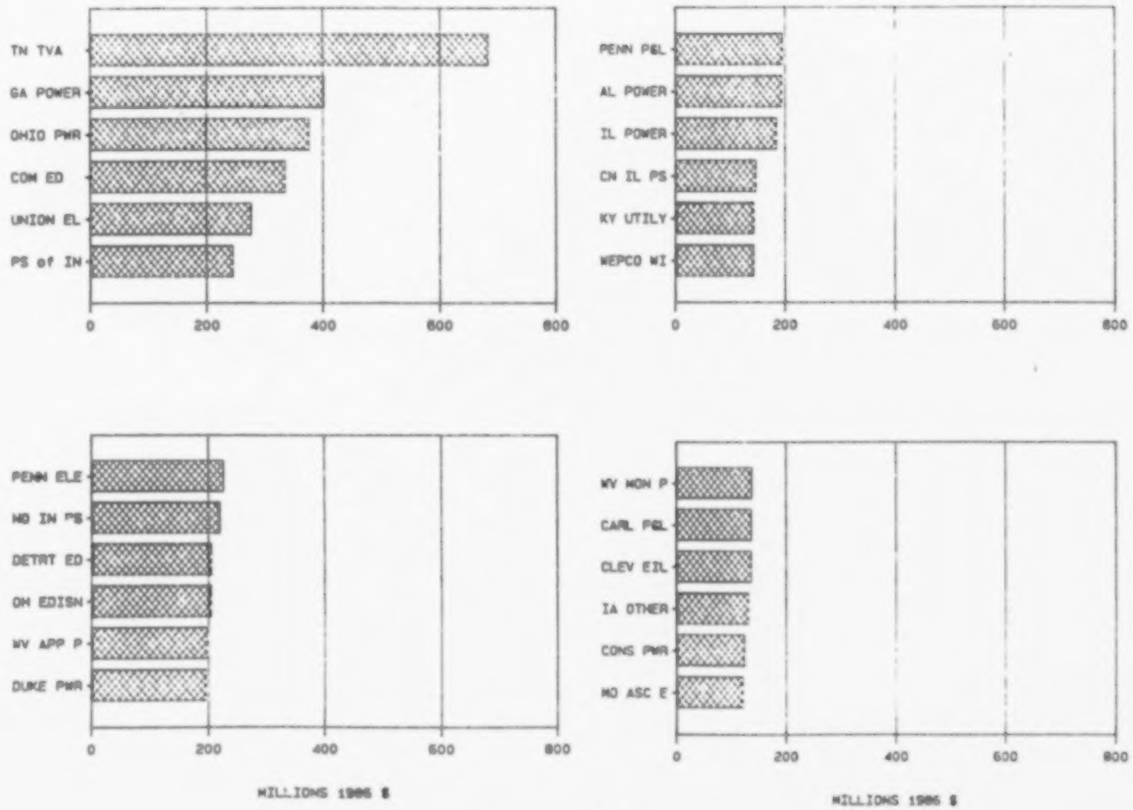
ESTIMATED UTILITY IMPACT FROM H.R. 4567
NATIONAL UTILITY REVENUE REQUIREMENTS



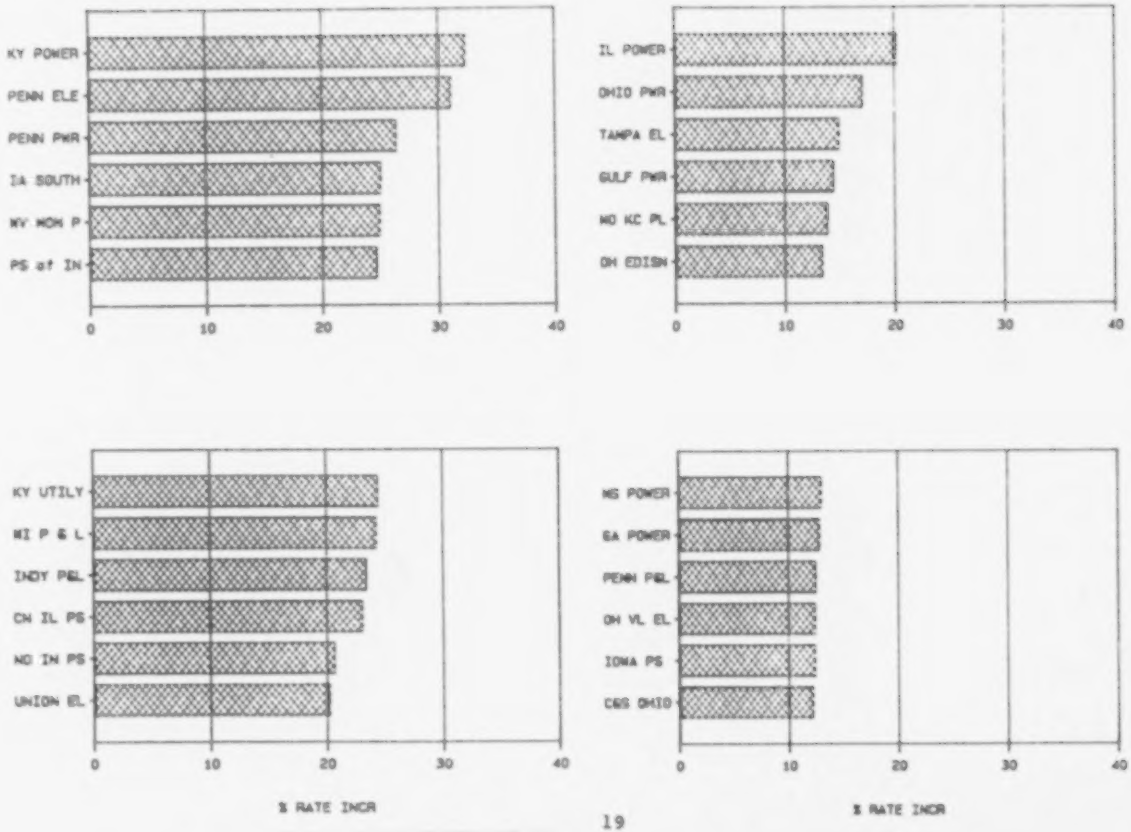
Annual Compliance Cost by State



H.R. 4567
ANNUAL REVENUE REQUIREMENTS
FOR THE HIGHEST IMPACT UTILITIES



AVERAGE RATE INCREASE
HIGHEST IMPACT UTILITIES



INDIVIDUAL UTILITY COMPANY
ANNUAL COMPLIANCE COSTS AND AVERAGE RATE INCREASES DURING FIRST 5 YEARS OF FULL COMPLIANCE

(1986 dollars)

	Annual Cost (million $)	Rate Increase %
AL-ALABAMA POWER CO	194	9
AL-OTHER	11	N/A
AL-TENNESSEE VALLEY AUTH	117	N/A
AR-ARKANSAS POWER & LIGHT	51	4
AR-OTHER	12	N/A
AZ-OTHER	5	0
AZ-SALT RIVER PROJECT	12	N/A
CO-COLORADO UTE ELEC ASSN	5	N/A
CO-OTHER	2	N/A
CO-PUBLIC SERVICE COLORADO	9	N/A
DE-DELMARVA POWER & LIGHT	20	3
FL-FLORIDA POWER CORP	74	5
FL-GULF POWER CO	72	14
FL-OTHER	13	N/A
FL-TAMPA ELECTRIC CO	167	15
GA-GEORGIA POWER CO	463	13
GA-OTHER	13	8
IA-IOWA PUBLIC SERVICE CO	31	12
IA-IOWA SOUTHERN UTILITIE	26	25
IA-OTHER	131	12
IL-CEN ILLINOIS PUBLIC SE	147	23
IL-CENTRAL ILLINOIS LIGHT	15	5
IL-COMMONWEALTH EDISON CO	336	6
IL-ELECTRIC ENERGY INC	49	36
IL-ILLINOIS POWER CO	105	20
IL-OTHER	28	N/A
IN-INDIANA & MICH ELEC CO	74	7
IN-INDIANA KENTUCKY ELEC	83	N/A
IN-INDIANAPOLIS POWER & L	108	23
IN-NO INDIANA PUBLIC SER	220	21
IN-OTHER	67	19
IN-PUBLIC SERVICE INDIANA	245	25
KS-KANSAS CITY POWER & LI	3	N/A
KS-KANSAS POWER & LIGHT C	11	2
KS-OTHER	31	N/A
KY-BIG RIVERS ELEC CORP	33	N/A
KY-EAST KENTUCKY POWER CO	19	N/A
KY-KENTUCKY POWER CO	85	32
KY-KENTUCKY UTILITIES CO	143	20
KY-LOUISVILLE GAS & ELEC	50	N/A
KY-OTHER	56	N/A
KY-TENNESSEE VALLEY AUTH	158	N/A
LA-CAJUN ELEC POWER COOP	24	N/A
LA-OTHER	11	N/A
MA-NEW ENGLAND POWER CO	91	8
MA-OTHER	23	8
MD-OTHER	54	3
MD-POTOMAC ELEC POWER CO	68	N/A
MI-CONSUMERS POWER CO	124	7
MI-DETROIT EDISON CO	205	8
MI-OTHER	38	22
MN-MINNESOTA POWER & LIGH	20	5
MN-NORTHERN STATES POWER	81	6
MN-OTHER	31	17
MO-ASSOCIATED ELEC COOP	121	N/A
MO-KANSAS CITY POWER & LI	86	14
MO-OTHER	79	19
MO-UNION ELECTRIC CO	277	26
MS-MISSISSIPPI POWER CO	58	12
MS-OTHER	16	N/A
MT-OTHER	7	3
NC-CAROLINA POWER & LIGHT	137	7
NC-DUKE POWER CO	196	7
ND-COOPERATIVE POWER ASSN	4	N/A
ND-OTHER	38	32
NE-NEBRASKA PUBLIC POWER	6	N/A
NE-OMAHA PUBLIC POWER DIS	4	N/A
NE-OTHER	1	N/A
NH-OTHER	30	6
NJ-OTHER	25	4
NJ-PUBLIC SERVICE ELEC &	78	3
NM-ARIZONA PUBLIC SERVICE	8	N/A
NM-PUBLIC SERVICE NEW MEX	6	1
NV-OTHER	3	0
NV-SOUTHERN CALIF EDISON	6	N/A
NY-NIAGARA MOHAWK POWER C	74	N/A
NY-OTHER	41	3
OH-CARDINAL OPERATING CO	110	N/A
OH-CINCINNATI GAS & ELEC	113	12
OH-CLEVELAND ELEC ILLUM C	136	10
OH-COLUMBUS & SO OHIO ELE	93	12
OH-DAYTON POWER & LIGHT C	93	N/A
OH-OHIO EDISON CO	204	13
OH-OHIO POWER CO	247	17
OH-OHIO VALLEY ELEC CORP	76	12
OH-OTHER	41	N/A
OK-OKLAHOMA GAS & ELEC CO	8	1
OK-OTHER	37	5
OR-OTHER	2	8
PA-DUQUESNE LIGHT CO	26	3
PA-OTHER	48	2
PA-PENNSYLVANIA ELEC CO	226	31
PA-PENNSYLVANIA POWER & L	196	13
PA-PENNSYLVANIA POWER CO	53	26
PA-WEST PENN POWER CO	79	9
SC-OTHER	66	N/A
SC-SOUTH CAROLINA ELEC &	79	11
SC-SOUTH CAROLINA PUBLIC	38	N/A
SD-OTHER	28	6
TN-TENNESSEE VALLEY AUTH	649	N/A
TX-HOUSTON LIGHTING & POW	10	0
TX-LOWER COLORADO RIVER A	4	N/A
TX-OTHER	8	1
TX-SOUTHWESTERN ELEC PWR	6	N/A
TX-SOUTHWESTERN PUB SER C	6	1
TX-TEXAS UTILITIES ELEC C	18	0
UT-UTAH POWER & LIGHT CO	16	1
VA-APPALACHIAN POWER CO	22	2
VA-OTHER	19	N/A
VA-VIRGINIA ELEC & POWER	49	N/A
WA-PACIFIC POWER & LIGHT	53	N/A
WI-OTHER	83	26
WI-WISCONSIN ELEC POWER C	143	12
WI-WISCONSIN POWER & LIGH	113	24
WV-APPALACHIAN POWER CO	107	N/A
WV-CENTRAL OPERATING CO	56	N/A
WV-MONONGAHELA POWER CO	138	25
WV-OHIO POWER CO	136	N/A
WV-VIRGINIA ELEC & POWER	56	N/A
WY-OTHER	5	N/A
WY-PACIFIC POWER & LIGHT	11	N/A

"ACID DEPOSITION CONTROL FUND"

- Intended to hold down highest rate increases and to encourage continuous emission controls through:

  --Interest subsidy payments on "qualified pollution control debt"

  --Through a nationwide fee of up to 1/2 mill per KWH on generation or imported energy, 1989 through 1996

- However, it appears that no utilities will qualify for it

  --Pollution control debt (for continuous emission controls) alone must cause residential rates to increase over 10 percent

  --Among 120 utility companies, even though total rate increases would exceed 10 percent for some utilities, the increase attributable solely to pollution control debt would be less than 10 percent for all of the utilities analyzed

OTHER ISSUES

- State implementation could raise costs--This analysis is based on an assumption that states would specify a utility companywide average emission rate and allow trading among units to reach that goal. Some states, however, might specify emission rates for individual unit and not allow intra-company emission trading, which could significantly increase costs.

- Monthly averaging time a disincentive for scrubbing--Any utility that balances off high emission rates as some units against a scrubber at another would be unable to meet the emission rate limitation in any month that the scrubbed unit was down for either planned or unscheduled maintenance.

- Deratings a significant cost of some low sulfur coals--Conversion of generating units to coals with significantly lower BTU contents, such as many Western low sulfur coals, can result in reduced power production and accelerated need for new plant capacity.

- Multiple coal supplies a potential problem at one plant--At some utility plants space and coal-handling equipment cannot accommodate compliance strategies that require different coal supplies for different generating units.

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ESTIMATING ACID RAIN CONTROL COSTS: ILLUSTRATIVE PROBLEMS FROM THE RECENT EEI-TBS STUDY OF H.R. 4567

Prepared at
Congressional Request

Larry B. Parker
Specialist in Energy Policy
Environment and Natural Resources Policy Division
April 29, 1986

ESTIMATING ACID RAIN CONTROL COSTS:
ILLUSTRATIVE PROBLEMS FROM THE RECENT EEI-TBS STUDY OF H.R. 4567

SUMMARY AND CONCLUSION

In discussing the implications of potential acid rain control legislation, legislators and analysts naturally focus attention on control costs and their economic effects. In particular, interested parties examine projected electricity rate increases to residential and other electricity consumers. However, despite their importance, and the mounds of cost studies conducted, Congress is still faced with electricity rate projections that are sometimes an order of magnitude apart on the costs of controls.

The most recent example of this situation relates to H.R. 4567. The bill involves States meeting a 1.2 lb. of SO2 per million Btu statewide limit on utility emissions, along with other reductions by other industrial concerns, by whatever means States choose to comply. In introducing the bill, sponsors made explicit reference to provisions in the bill to help States prevent residential electricity rates from increasing more than 10 percent because of control equipment costs. This assistance comes in the form of an interest subsidy to be funded by a fee of 1/2 mill per kilowatt-hour (kwh) on non-nuclear, non-hydro power generated or imported into the country.

Four days after introduction, the Edison Electric Institute (EEI) released a study conducted by Temple, Barker & Sloane (TBS) stating that residential rate increases would be much more than 10 percent for many of the country's utilities--over 30 percent in the case of Kentucky Power Company. Regarding the interest subsidy, the EEI-TBS study suggested that no utility met the requirements of the interest subsidy despite the study's projected high residential rate increases.

Like most other things involved with the acid rain controversy, cost studies have a political content. Because one can vary the decision-making process, the provisions of the proposed program, and the necessary cost assumptions in conducting cost analysis, it is not always easy to tell if a study's result flows from prior stated assumptions, or from result-oriented procedures that have to be understood before the study's usefulness can be assessed. This is particularly true of a bill like H.R. 4567 which is designed to provide maximum flexibility to States in implementing its provisions and whose deadlines are well into the future.

The EEI-TBS report does not take advantage of the flexibility or opportunities for cost-effective or imaginative responses provided by H.R. 4567. This is somewhat paradoxical as utilities' concerns about constraints being imposed on how they could meet any acid rain requirement were a primary consideration to drafters of the bill in deciding to provide as much flexibility to States as possible in designing reduction strategies. Indeed, the compliance strategy chosen by TBS for the individual utility reanalyzed in this report was not the most cost-effective available to the utility. The implication of the EEI-TBS study that utilities would not seriously examine opportunities for innovative and cost-effective responses in designing reduction strategies under H.R. 4567 seems questionable in light of State concerns and the utilities own self-interest.

Utilizing some, but not all, of the flexibility provided by H.R. 4567, CRS analyzed one utility studied in the EEI-TBS report (Kentucky Power Company) and found compliance options necessitating rate increases substantially less than those projected by TBS. Using a range of possible control methods, CRS projected rate increases from Kentucky Power Company of between 4.3 percent and 10.4 percent first-year, and 1.8 percent and 6.5 percent average over 20 years. These results compare with a EEI-TBS estimate of an above 30 percent firstyear rate increase and a CRS recalculation of the EEI-TBS scenario of 24.2 percent first-year and 10.2 percent average over 20 years.

INTRODUCTION

In discussing the implications of potential acid rain legislation, legislators and analysts naturally focus on control costs and their effects. However, despite their importance, and the mounds of cost studies conducted, Congress is still faced with estimates that are sometimes an order of magnitude apart on the cost of controls. The introduction of H.R. 4567 illustrates this situation. In introducing the bill, sponsors made explicit reference to provisions in the bill to help States prevent residential electricity rates from increasing more than 10 percent because of control equipment costs. However, four days after introduction, the Edison Electric Institute (EEI) released a study conducted by Temple, Barker & Sloane (TBS) stating that residential rate increases would be much higher, over 30 percent in the case of Kentucky

Power Company. 1/

This paper attempts to provide insight on the potential and pitfalls of acid rain cost analysis, using the EEI-TBS study of H.R. 4567 as an example. Many of the points raised are applicable to virtually all acid rain cost studies. The discussion is divided into four generic areas: (1) How the study handled H.R. 4567's decision-making process, (2) How the study interpreted H.R. 4567's various provisions affecting costs, (3) Methodological issues (including scope and assumptions), and (4) An example from the EEI-TBS report. It should be noted that the issues raised in this analysis are illustrative, not comprehensive.2/ Also, the analysis assumes a working knowledge of H.R. 4567 on the part of the reader.

DECISION-MAKING

The central decision-making authority under H.R. 4567 is the individual State government. The State may become as involved in the reduction process as it desires, including choosing sources to be controlled, methods to be used, and how costs are to be distributed. With the bill's statewide bubble and no restriction on control methods, the State may choose the most cost-effective control strategy for its consumers; or, using the bill's interest subsidy provision, the State may choose to

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1/ Temple, Barker, & Sloane, Inc. Economic Evaluation of H.R. 4567: The "Acid Deposition Control Act of 1986". Prepared for the Edison Electricity Institute, April 14, 1986.

2/ For other cost-related issues in acid rain cost analysis, see Parker, Larry. Summary and Analysis of Technical Hearings on Costs of Acid Rain Bills. Prepared at the request of the Committee on Environment and Public Works, U.S. Senate. CRS unnumbered report, July 26, 1982.

trade some cost-savings to electricity consumers for high-sulfur coal production savings for its coal miners by installing some less cost-effective control technology. In either case, the State is in control.

Attempting to put the above political decision-making process into an economic analysis presents difficulties for cost analysts. Generally, the analyst must put himself in the place of the State government and make basic assumptions on how the bill would be implemented. In many studies, including the EEI-TBS study, the State role is generally ignored and the individual utilities are the focus point of the analysis. Depending on the analyst, individual utilities may or may not be adopting cost-effective strategies. For example, the EEI-TBS study assumes 74 gigawatts of flue gas desulfurization (FGD) capacity would be installed under H.R. 4567. (FGD is the generally the most expensive and capital-intensive control technology). This compares with 10-30 gigawatts of FGD projected by the Congressional Office of Technology Assessment (OTA) and ICF, Inc. for reductions of similar magnitude. 3/ Such a fundamental difference in the estimated proportion of utilities choosing one or another control method (particularly a capital-intensive method such as FGD) has a dramatic impact on rate estimates. Since TBS assumes twice as much FGD as other studies, it is not surprising that its projected costs are

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3/ The difference probably results from differing definitions of cost-effectiveness. OTA and ICF define cost-effectiveness in terms of the control method which is least-cost to the utility. In its study of H.R. 3400 conducted in 1983, TBS defined cost-effective FGD candidates as generating units of 200 megawatts or more built since 1960, or remaining units built since 1965. This assumption results in considerably more FGD being installed than an assumption based on least-cost to the utility. As suggested by the example of Kentucky Power Company presented later in this paper, TBS may have used a similar definition for this analysis.

higher, particularly during the first few years.

Hence, how the analyst views the actual decision-making process of acid rain bills influences his results. The EEI-TBS study uses utilities as the focus of the study with FGD as the primary control technique. Such a focus does not necessarily model the actual decision-making process under H.R. 4567; and, it certainly does not result in the most cost-effective strategy possible under the bill.

H.R. 4567 PROVISIONS

As written, H.R. 4567 is designed to provide maximum flexibility to the States in deciding how to reduce emissions. Important provisions in this regard include no restriction on control methods, a statewide emissions rate standard allowing bubbling 4/ of emission sources, and an interest subsidy for States who wish to protect their high-sulfur coal production without dramatic residential rate increases. As suggested above, this flexibility permits a State to choose a least-cost, polluter-pays strategy, if it wishes; or, to protect its high-sulfur coal production.

Models used by OTA, ICF, and Data Resources Inc. (DRI) permit analysts to incorporate much of the flexibility permitted by H.R. 4567 in their studies. Analysts still must guess the position of State Governments in deciding overall strategy as discussed above; however, one can run different scenarios to indicated how differing State policies affect costs. For example, a recent ICF analysis for the Environmental Protec-

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4/ A bubble permits a company (or State) to meet an average company-wide emission limit, rather than requiring compliance at each individual emission source.

tion Agency (EPA) contained two scenarios each for a six and eight million ton reduction: (1) least-cost only, and (2) least-cost but including 27.2 gigawatts of the most cost-effective FGD. 5/ Other studies have been conducted to include dry scrubbing and Limestone Injection Multi-stage Burners (LIMB) technology as additional control methods; these additional techniques are definite control possibilities for compliance with H.R. 4567, given the bill's 1997 compliance deadline for part 2. Different scenarios are not only useful in debating the cost of acid rain control, but also for identifying potential implementation strategies if such legislation is passed.

The EEI-TBS study incorporates little, if any, of the flexibility of H.R. 4567 in its analysis; it does not make use of the 1.2 lb. of SO2 per million Btus statewide bubble, the potential for new technology, or least-cost strategies. The study defines the interest subsidy provisions in such a way as to provide no relief to utilities because no one is eligible (by TBS's definition).

METHODOLOGY

Methodology and assumptions inevitably affect conclusions, sometimes in non-obvious ways. Five categories of variations are described below.

> 1. Definition of Cost: Definitions of what should be included as acid rain "control costs" have a substantial impact on estimated program costs. Generally, incremental capital, operations and maintenance costs, and fuel costs for pollution control equipment or fuel switching are accepted as reasonable expenditures to be charged to an acid rain program. However, other costs, such as replacement capacity or energy for scrubber retrofits, are considered more

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5/ ICF Incorporated. Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year 1.2 lb. Sulfur Dioxide Emission Reduction Cases. Prepared for the Environmental Protection Agency, February 1986.

arguable. The EEI-TBS study mentions a 5.5 percent penalty for scrubber retrofits, but not how that penalty is assessed. The study also assumes that acid rain control would have an immediate and substantial price impact on the low-sulfur coal market, despite its current depressed state. Because of this assumption, the study assigns a cost premium to low-sulfur coal currently being burned by utilities.

2. Cost Estimates: Capital cost estimates for FGD used in acid rain analyses vary significantly: from $155 (TVA) to $450 (AEP) a kw in various utility studies. Similarly, premiums for low-sulfur coal also vary, from $0 to $30 a ton. The capital cost estimates used by TBS in their analysis are about 10-20 percent higher on average than EPA estimates. However, variable operations and maintenance costs used by TBS are almost 8 times greater.

3. Alternatives Available: Even through any acid rain program would not be fully implemented until the 1990s (the mid 1990s in the case of H.R. 4567), many acid rain analyses constrain their control alternatives to a couple of currently available technologies. Several technologies are emerging which may significantly reduce reduction costs. With the flexibility and relatively long lead times of H.R. 4567, this assumption is particularly important. The EEI-TBS study examines only three alternatives for control: wet FGD, fuel switching, and plant retirement.

4. Financial Parameters: If the acid rain strategy being proposed is capital-intensive, financial parameters can have a significant impact on apparent costs. This impact can be emphasized by the way the study's results are presented. The EEI-TBS study provides few details on its financial assumptions.

5. Presentation: There are several ways to present acid rain costs. If the acid rain control strategy being proposed is capital--intensive, first-year costs may be roughly double the average cost of the program over the life of the equipment. Also, because of the accelerated tax depreciation (ACRS) available, the first five-years of the program will be disproportionately higher than the rest of the program's life. A second aspect of presentation is the baseline chosen. For various reasons, many analyses present results in terms of rate increases from current or past rates. This method assumes that electricity rates will remain the same in real terms until the 1990s when the program would be implemented. The EEI-TBS focuses its presentation on first-year and five-year levelized costs and rate impacts. The base year used for the rate impact is not stated. No levelized rate impacts for the life of the equipment are provided.

AN EXAMPLE: KENTUCKY POWER COMPANY

In order to illustrate some of the considerations discussed above, a utility from the EEI-TBS study has been chosen for closer examination. The utility chosen is Kentucky Power Company (KPCo). KPCo is a 1097 megawatt utility with a two unit generating station--Big Sandy (unit 1: 281 Mw, 1963; unit 2: 816 Mw, 1969). Current SO2 emissions from the plant are under 2.0 lbs. per million Btus and within SIP requirements.

KPCo was chosen for this discussion for two reasons. First, according to the EEI-TBS report, KPCo will have the highest residential rate increase under H.R. 4567 at over 30 percent, showing that H.R 4567 would have very high costs for some utilities. 6/ Second, for the purposes of this discussion, the utility does not have some of the complexities of other systems because KPCo has only one power station and no stage 1 reductions.

Methodology Used

To provide some comparability between the EEI-TBS analysis and the alternative scenarios developed by CRS, this CRS study employs TBS's allocation formula for KPCo. Based on 1983 excess emissions above 1.2 lb. per mmBtus, TBS estimates that KPCo would have to reduce SO2 emissions by

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6/ It is interesting to note that KPCo was the utility projected in 1982 by American Electric Power to experience a 106.4% rate increase from acid rain legislation proposed at that time (S. 1706). The same reduction method used in this older analysis is used by TBS in the EEI-TBS study, although the rate increase has dropped. See American Electric Power Service Corporation. Economic Impact on the AEP System of Compliance with the Mitchell Bill, February 23, 1982.

16,393 tons under H.R. 4567 from a total of 44,574 tons. [7] This works out to a system reduction of 37 percent.

To achieve this reduction, the EEI-TBS study assumes KPCo will install a wet scrubber on unit 2. Assuming proportionate emissions between the two units and 90 percent removal by the scrubber, this action would result in 29,841 tons of SO2 removed. This is considerably more than is necessary, given TBS's allocation formula--particularly since the EEI-TBS report does not incorporate H.R. 4567's statewide bubble, and therefore assumes the utility will not be able to sell the excess reduction. [8]

CRS developed five scenarios for KPCo to indicate the range of control possibilities available, and the influence of assumptions on costs. While these scenarios allow us to examine some of the issues raised above, they do not incorporate all the flexibility and cost effectiveness opportunities available in H.R. 4567. The scenarios are as follows: [9]

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[7] It should be noted that this is not the allocation formula mandated under H.R. 4567 which has no baseline year or percentage reduction requirement. It is employed here only to provide some comparability between the EEI-TBS report and the scenarios presented here.

[8] Based on 1983 SO2 emission rates as developed by Energy Ventures Analysis, Inc. for Big Sandy, the EEI-TBS scenario would result in a company-wide emission rate of .6 lb of SO2 per million Btus. 1983 data from Energy Ventures Analysis, Inc. Evaluation of SO2 Emissions and the FGD Retrofit Feasibility at the 200 Top Emitting Generating Stations. Prepared for the U.S. Environmental Protection Agency, January 10, 1986.

[9] Based on 1983 SO2 emission rates as developed by Energy Ventures Analysis, Inc. for Big Sandy, the four CRS scenarios would result in a company-wide emission rate of 1.07 lb. of SO2 per million Btus--sufficient to meet the 1.2 lb of SO2 per million Btu average on a monthly basis as specified in H.R. 4567. 1983 emission rate data from Energy Ventures Analysis, Inc. Evaluation of SO2 Emissions and the FGD Retrofit Feasi-

Scenarios

1. EEI-TBS. This scenarios assumes the reduction strategy as employed by TBS in their analysis. Cost assumptions are the same as in the report; however, other assumptions, including NOx costs, replacement costs, and financial parameters have been changed to make them consistent with the other scenarios.

2. Adequate FGD. Under this scenario, unit 2 is equipped with a wet scrubber only sufficient to removed the SO2 required. With a 90 percent efficient scrubber, 55 percent of unit 2's stack gases are scrubbed. Such a strategy would require a scrubber with about 450 Mw capacity.

3. Dry Scrubbing. Dry scrubbing is a recent technology particularly suited to plants which burn low to medium sulfur coals, such as Big Sandy. With the dry scrubber operating at 50 percent removal, all of unit 2's stack gases would be scrubbed under this scenario.

4. LIMB Technology. LIMB (Limestone Injection Multi-Stage Burners) is a developmental technology which would probably be available for commercial use by the late 1980s or early 1990s. With 50 percent removal, all of unit 2's stack gases would be scrubbed under this scenario.

5. Fuel-Switching. Sited in the heart of eastern low-sulfur coal deposits, KPCo might very well decide to fuel-switch its facility to achieve the necessary reductions. Under this scenario, both unit 1 and unit 2 would switch their coal to compliance quality.

Assumptions

These five scenarios are compared with each other according to the below assumptions.

Wet FGD Costs. For the EEI-TBS scenario, CRS used TBS's assumption of $280 a kilowatt installed for capital costs. Operations and maintenance costs of $13 a kw for fixed costs and 1.7 mills per kwh for variable costs are assumed, as specified in the report. CRS assumes TBS's 1986 dollars are really end of 1985 dollars.

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bility at the 200 Top Emitting Generating Stations. Prepared for the U.S. Environmental Protection Agency, January 10, 1986.

For the Adequate FGD scenario, CRS used EPA estimates for a 500 kilowatt scrubber burning 1.67 lb. of SO2 per million Btu coal inflated by the GNP implicit price deflator to end of 1985 dollars and incorporating a 1.3 retrofit factor. This resulted in a $235 a kilowatt capital cost. Operations and maintenance costs were derived similarly (including a 1.3 retrofit factor for fixed O & M), and were $11.7 per kw for fixed costs and .22 mills per kwh for variable costs.

Dry Scrubbing Costs. For the Dry Scrubbing scenario, CRS used EPA estimates for a 500 kilowatt dry scrubber operating at 50 percent efficiency and burning 1.67 lb. of SO2 per million Btu coal inflated by the GNP implicit price deflator to end of 1985 dollars and incorporating a 1.3 retrofit factor. This resulted in a $125 a kilowatt capital cost. Operations and maintenance were derived similarly, and were 1 mill per kwh.

LIMB Costs. For the LIMB scenario, CRS used EPA estimates for a 500 kilowatt LIMB system operating at 50 percent efficiency and burning 1.67 lb. of SO2 per million Btu coal inflated by the GNP implicit price deflator to end of 1985 dollars. This results in a $50 a kilowatt capital costs. Operations and maintenance were derived similarly, and were .7 mills per kwh.

Coal Price Differential. Current coal price differentials for low-sulfur coal range from $0 a ton to $5 in the current market. Under an acid rain bill, the demand for low sulfur coal could drive this differential back up to previous levels of $5 to $10 a ton. For this analysis, CRS assumed that the differential would be $10 a ton by the time the 1997 compliance deadline appeared.

Upgrading Costs. Switching Big Sandy to even lower-sulfur coal than it already burns might involve adjustments to the boiler or ancillary equipment such as grinders or the plant's ESP. For this analysis, CRS assumed that these costs were $10 a kilowatt.

Financial Parameters. Based on DOE data and CRS estimates, table 1 summarizes the financial assumptions made about KPCo. 10/ From these assumptions, nominal and real capital charge rates were calculated--16.5 percent nominal, 11.8 percent real. All calculations are in constant end of 1985 dollars.

Table 1: Financial Assumptions for Analysis

Return on Equity	14 percent
Average Weighted Cost of Debt	10 percent
Debt ratio	60 percent
Nominal Discount Rate	10 percent
Real Discount Rate	5 percent
Percent of Investment as AFUDC	10 percent
Property Taxes/Insurance	2 percent
Equipment Service Life	20 years
Tax Depreciation	5 year ACRS

Electricity Demand. CRS assumed that KPCo electricity demand will increase at 1 percent a year from its 1984 levels during the 20 year life of the program.

NOx Costs. Big Sandy's NOx emissions are approximately .8 lbs. of NOx per million Btus. With a reduction of only 25 percent necessary for KPCo to meet H.R. 4567 NOx requirement, it is not clear that the $10 a kilowatt low-NOx burners assumed by TBS in 75 percent of all cases would

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10/ Department of Energy. Financial Statistics of Selected Electric Utilities, 1984. DOE/EIA-0437(84). January 1986.

be necessary in this case. Therefore, for the purposes of comparison, NOx costs were not included in this analysis.

This deletion does not represent a major cost item. Assuming KPCo chose to use low-NOx burners to achieve its reduction, a retrofit of unit 2 would be sufficient. Assuming TBS's $10 a kw cost estimate, this scenario would result in a .66 percent first-year rate increase and a .17 percent 20-year levelized rate increase. For readers which wish to include this NOx scenario to the SO2 scenarios presented later, the results are additive. However, the NOx cost should not be added to the LIMB scenario as that technology is a simultaneous SO2 and NOx reduction technology.

Replacement Capacity. Using EPA estimates, the capacity loss under the Adequate FGD scenario would be about 20 megawatts. CRS has assigned no cost to this loss in capacity because of the short and long term reduction in demand the increased costs of electricity from the retrofit would bring. Even if one assumes a low -.2 electricity price elasticity in the short-term and -.5 in the long term, the short and long term rate increases projected for this scenario should cause demand reductions sufficient to "replace" the capacity lost to the retrofit. 11/ Hence,

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11/ While electricity price elasticities for the residential sector are generally accepted to be -.2 (short-term) and -.7 (long-term), commercial and industrial elasticities are more uncertain. There is evidence that commercial electricity demand is elastic, more so than in the residential sector. On this point, see Parker Larry B "Commercial Consumption", in J. Schanz. U.S. Energy Outlook: A Demand Perspective for the Eighties. A report for the Committee on Energy and Commerce, U.S. House, July 1981. There is also evidence that the industrial elasticity in the long-term is in the range of -.5 to -1.0 Hence, to be conservative, we have assumed inelastic short-term and long-term price elasticities of -.2 and -.5 respectively. For a general discussion of energy elasticities, including electricity price elasticities, see Bohi, replacement costs probably should not be charged to H.R. 4567 in this case. The same is true for the EEI-TBS scenario, and is so analyzed in this paper. Capacity losses under the Dry Scrubbing and LIMB scenarios would be about half those under the Adequate FGD scenario or less than 1 percent of KPCo total capacity. As with the FGD cases, it is assumed the demand reduction would be sufficient to cover the minor loss in capacity.

Results

Using a utility cost model developed by CRS, and assuming January 1, 1985 residential rates for KPCo as published by DOE 12/, table 2 presented projected first-year and 20-year levelized residential rate increases under the various scenarios. As indicated, the LIMB scenario is the least-cost strategy under the assumptions of this analysis, while the EEI-TBS scenario is the most expensive.

Table 2: Residential Rate Increases Under Five Scenarios

	Scenario				
	EEI-TBS	Adequate FGD	Dry Scrubbing	LIMB	Fuel Switching
First-Year Rate Increase	24.2%	10.4%	9.6%	4.3%	7.8%
20-Year Levelized Rate Increase	10.2%	4.0%	3.5%	1.8%	6.5%

Douglas R. Analyzing Demand Behavior: A Study of Energy Elasticities. Published for Resources for the Future, Baltimore: John Hopkins University Press, 1981.

12/ Department of Energy. Typical Electric Bills, January 1, 1985. DOE/EIA-0040(85) December 1985.

Several observations can be made. First, the CRS recalculation of the EEI-TBS scenario results in a considerably reduced first-year rate impact than that reported in the actual report--24.2 percent versus over 30 percent. There are probably several reasons for this difference. The primary reason is likely the removal of replacement costs from the analysis. As noted earlier, the EEI-TBS mentions a 5.5% energy and capacity penalty in discussing its key financial assumptions. However, the report does not explain how it accounts for this penalty in terms of additional costs. Also, as noted previously, the EEI-TBS study includes costs for low-NOx burners, which this comparison does not. (Although as calculated earlier, this is only a minor cost addition.) Differences may also arise from different financial parameters, although there is no way of assessing the impact as they are not presented in the EEI-TBS report.

Second, this example suggests that the EEI-TBS report is not strictly based on a least-cost implementation strategy, although H.R. 4567 provides that flexibility. The EEI-TBS study states that its assumed utility decision order for achieving SO2 reductions is fuel switching first, scrubbing second, and retirement last. Such an order would suggest some roughly based cost-effectiveness criteria. However, assuming the EEI-TBS scenario presented here represents the scrubbing decision in the EEI-TBS report, it seems clear under the assumptions of this analysis that KPCo should follow the first decision and fuel-switch its plant to achieve the reduction under H.R. 4567. The cost differential identified in table 2 would be even greater if EEI-TBS study results were correct.

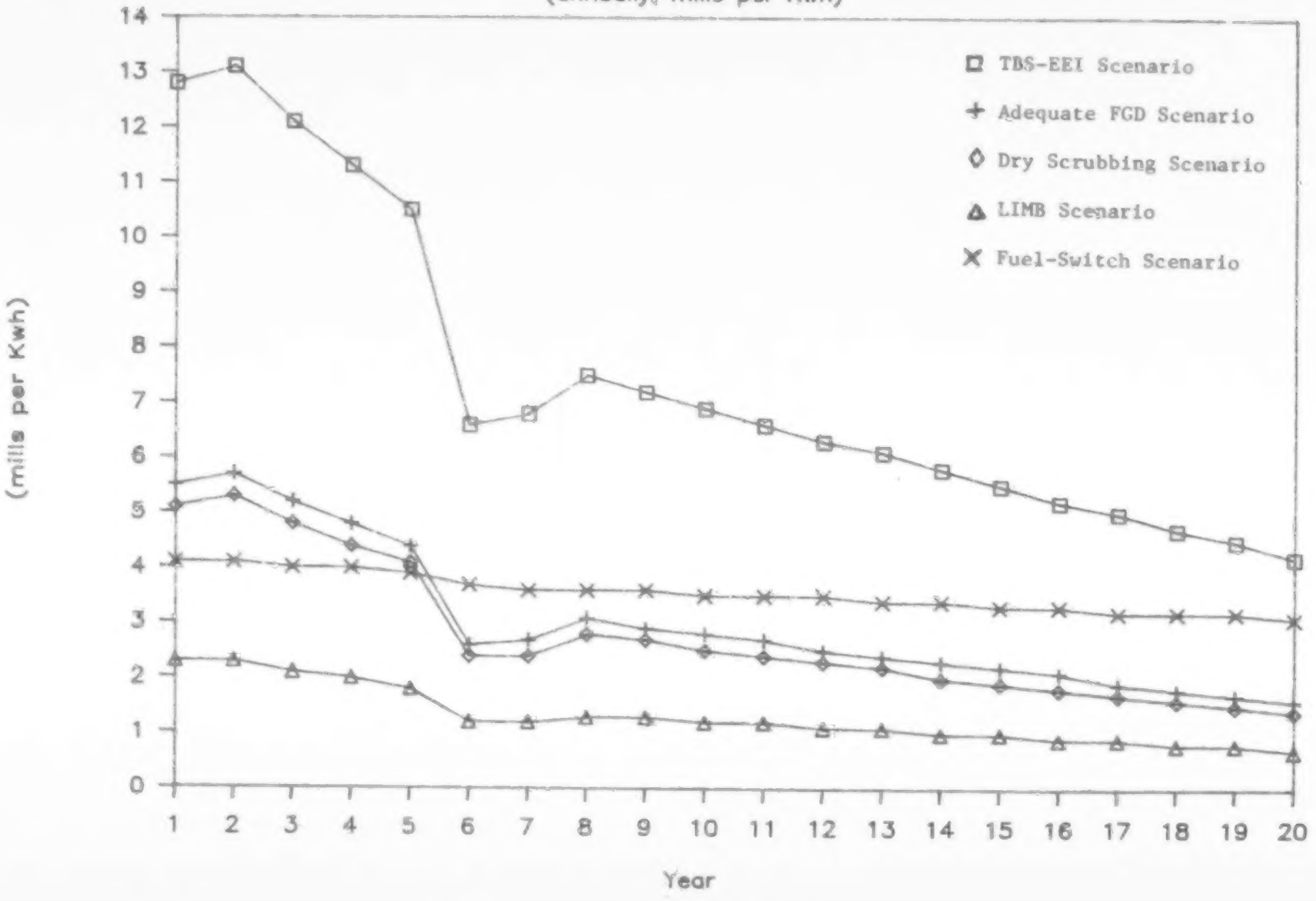
A third observation which can be made is that if scrubbing is scaled back to that adequate for the H.R. 4567 reduction, the utility can achieve a significant savings over the EEI-TBS scenario. Indeed, under the assumptions of this analysis, partial scrubbing is competitive with fuel switching.

Fourth, if available technologies are not constrained to a couple of currently available methods, recently developed and emerging technologies (at currently projected costs) could significantly reduce costs. In this analysis, dry scrubbing comes in at slightly less than the Adequate FGD scenario while the LIMB scenario is the most cost-effective alternative (even not including its simultaneous NOx reduction).

The above rate impacts are based on first-year and 20-year levelized costs. Both numbers are presented to provide the reader with both the short-term and longer-term impact of the scenarios. To examine presentation issues more closely, figure 1 plots annual cost in mills per kwh for each of the five scenarios. The trends are quite revealing. As expected, the fuel switching trend is relatively flat as most of the additional cost is for fuel. This contrasts strongly with the EEI-TBS scenario which remains high for about five years and then drops significantly. This drop is due to the capital intensiveness of the scenario and the accelerated tax depreciation available for pollution control equipment.

Figure 1: Reduction Cost for Scenarios

(annually, mills per Kwh)



ACID RAIN CONTROL COSTS
RESPONSE TO A CRITIQUE BY
THE CONGRESSIONAL RESEARCH SERVICE

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INTRODUCTION

On April 10, 1986, a new bill for acid rain control (HR4567) was introduced in the House of Representatives with an unusually strong base of support. Since its introduction, the bill has received much attention, including three days of Congressional hearings and the release of studies by the Office of Technology Assessment, the Edison Electric Institute, and the Environmental Protection Agency.

The Edison Electric Institute (EEI) report--Economic Evaluation of HR4567, April 14, 1986--estimated the costs of compliance associated with the House bill by analyzing the bill's requirements, determining the most likely methods of utility compliance, and assessing the consequent costs, including their distribution and their impact on customer rates. The EEI report was subsequently criticized in an April 29, 1986 report prepared by the Congressional Research Service (CRS). The EEI report was prepared by Temple, Barker & Sloane, Inc. (TBS) of Lexington, Massachusetts, and this document contains TBS's response to CRS's criticisms.

On a broader front, TBS is concerned about the way in which cost estimates are being presented to Congress for decision making on this bill. OTA, ICF, and CRS all tend to present or at least emphasize costs that are "levelized" over 20 years and averaged across entire states. That's relevant for some purposes, but it's not appropriate in evaluating potential "rate shock" for utility customers, because the actual rates can vary significantly from utility to utility within a state and would be higher in the early years than they would be later. For example, a rate increase of about 6 percent is all we at TBS would project for Pennsylvania on a levelized, statewide basis, but for individual utilities, we estimate increases of over 20 percent in the first five years for two of the five companies in the state.

Similarly, critics of the EEI report have focused on the relatively high volume of scrubbing that TBS projected under this bill. At the same time, however, there has not been open disclosure about just how much coal switching is assumed in the ICF and OTA estimates. In fact, the ICF figures on utility fuel consumption indicate that their cost estimate is based on a range of from 180 to 280 million tons of coal switching in the eastern 31 states by the year 2000, when total coal consumption there would be approximately 700 million tons (see Table B-3). This constitutes such a large proportion of the total coal usage, that it should be stated explicitly. Furthermore, it is TBS's view that this volume is so large that the potential economic isolation it could cause would lead states to force more widespread usage of scrubbers than ICF has so far estimated.

Summary

The major points that are made in the following pages in response to the CRS critique can be summed up briefly in the following statements:

- TBS's results are consistent with those of the other major studies. In particular, when expressed on a comparable basis, they are within the range of costs estimated by EPA and are just over ten percent higher than the range estimated by the Office of Technology Assessment.
- CRS's sample of one powerplant is an insufficient basis for generalization. The TBS analysis dealt with all of coal-fired powerplants in the country in an attempt to identify the broad range of impacts that this bill could have. No one can predict exactly what type of controls might be required by the state or selected by the utility for an individual power plant, so any thorough evaluation must address costs across a range of utilities and plants. The TBS results are consistent with, or even lower than, the independent estimates of the majority of utility companies that have commented on our analysis to date.
- TBS's cost projections for Kentucky Power are conservative for scrubbing, but are high if the utility wefe able to rely on coal switching to comply. TBS's cots for switching to low sulfur coal at this company's single plant would be within five percent of CRS's estimate. If the utility were required to scrub instead, then the TBS estimates appear conservative since the utility company has prepared cost estimates almost twice as high in the past for use with the investment banking community.
- The exclusion of innovative technologies is conservative and fits the schedule in the bill. Since the bill requires states to develop and submit their state compliance plans within one year after enactment, there is simply not enough time for utilities or states to gamble on technologies that are not commercially proven.
- We have provided responses to a number of specific criticisms of the TBS methodology and assumptions, including:

  --TBS capital cost estimates for scrubbers are consistent with EPRI data

--TBS operations and maintenance costs for scrubbers are consistent with those used by others, including estimates cited last year by CRS

--TBS's unit costs for switching to low sulfur coal are reasonably close to CRS's; in fact, for the Big Sandy plant they're within five percent on an annualized basis

--NOx control costs are included, but are conservative in TBS's analysis

- CRS's own methodology has a significant downward bias. CRS introduces the concept of demand elasticity as its reason to exclude costs for replacement power, an argument which we do not fully accept. However, if they are to use it, then to be consistent they should also include the effect that such demand reductions would have in requiring the base rates of the remaining usage to increase in order to continue to cover the fixed costs of utility systems. With the long-run elasticity rate that CRS uses, such adjustments could add another four percentage points to a rate increase that would otherwise be estimated at twenty percent.

TBS's responses to CRS's major criticisms are presented in the sections below.

TBS'S RESULTS ARE CONSISTENT WITH THOSE OF THE OTHER MAJOR STUDIES

The objective of the TBS report for EEI was to provide a broad national evaluation of the total costs of HR 4567 and the range of localized impacts that would be felt by customers of individual utility companies. Judging the report at its broadest level, its results on both of those dimensions appear to be consistent with other major studies, when expressed in comparable terms.

The TBS estimate of $9.2 billion total annual cost for the peak five-year period under HR 4567 is equivalent to $4.8 billion, when levelized over 20 years, converted from 1986 to 1985 dollars, and adjusted to exclude NOx costs, which neither EPA nor OTA included. That figure is within the range of $3.1 to $5.8 billion of electric utility costs that EPA estimated for this bill. It is also only 12 percent above the upper end of the $3.4 to $4.3 billion range that OTA projected for utility costs.

Obviously, if the EPA and OTA figures were adjusted in the other direction, to focus on the peak years and to include NOx control costs, they would fall generally in the range of $6 to $10 billion, near TBS's $9.2 billion estimate.

The state-to-state comparisons of required SO_2 reductions and annualized costs follow patterns that are very similar for almost all states in the three reports. Except for a few isolated differences such as Wyoming, which was shown with a large reduction requirement in the OTA analysis, the same groupings of states for the highest and lowest impacts show up in all three reports.

There also seems to be substantial agreement among the estimates of percentage rate increases, when expressed on the same basis. Administrator Lee Thomas of EPA testified that EPA projections show rate increases in the initial years would be as high as 10 to 15 percent in a number of states, with individual utility companies in some cases experiencing increases of over 20 and 30 percent. The TBS estimates (from approximately 120 utility companies with significant coal-fired capacity) are consistent with these estimates, showing 13 utilities with five-year rate increases between 20 and 30 percent and three utilities above 30 percent.

CRS'S SAMPLE OF ONE POWERPLANT IS AN INSUFFICIENT BASIS FOR GENERALIZATION

To assess the broad national and regional effects, and the range of localized effects, that this bill would have, the TBS analysis dealt with approximately 1100 coal-fired electric generating units at approximately 400 powerplants and 120 electric utility companies in the United States.

In evaluating all those individual powerplants, we did not expect to be exactly right on any individual powerplant, but to develop estimates based on what would be a reasonable overall compliance strategy for a utility, taking into account the emission rates, sizes, ages, boiler designs and capacity factors of all of its coal-fired units.

The CRS critique is based on a detailed evaluation of just one powerplant which, by itself, constitutes a single utility company. That company, the Kentucky Power Company and its Big Sandy plant, is an unusual instance. Of all the utility companies analyzed by TBS, only five are single powerplant companies, and the other four exist solely to serve individual large-scale industrial facilities, such as an aluminum smelter or a uranium enrichment facility.

Any thorough evaluation of the TBS analysis must address a range of utilities and compliance strategies, including some from different regions of the country. Ideally, such a review would include some of the largest utility systems that would account for the greatest emissions reductions and overall costs, and that could consider a mixture of compliance strategies across their plants. One would expect that such a review would identify not only a number of utilities for which a detailed review corroborated the TBS estimates, but also some utilities for which a more detailed analysis indicated lower costs, and some for which it indicated higher costs. That would be the natural consequence of obtaining greater detail on the local circumstances of the plants, coal contracts, transportation access and so on, and more insight into the policies of state officials and utility managements regarding the use of various control technologies.

Since performing the EEI analysis, TBS has received inquiries and comments from a number of utility companies regarding the costs we have estimated for their systems. These contacts have provided a quick "litmus test" of the projections, which generally fit that pattern. The majority of the utilities from which we have heard indicated that the TBS estimates are either very close to their own or are even lower than their projections. A list of those companies that had sufficiently evaluated their own costs to provide judgments about the TBS estimates is attached to this document. (It should be emphasized that most of these contacts were informal and that listing the utility company names in the Attachment is for information only and does not necessarily imply official corporate endorsements of the TBS study.)

The only pattern that is suggested by the responses is that the TBS analysis may be most accurate, or even understated, for the larger utility systems that are heavily dependent on eastern coal and for systems in the West that rely almost exclusively on western coal. It appears that the analysis has had the greatest difficulty in estimating costs for some systems that have already begun a transition to western low sulfur coal and may have future coal prices already locked into long-term contracts, or that are using significant quantities of natural gas now.

The comments of the utilities have also indicated that the NOx requirements of the bill could be much more difficult and expensive for them than any of the studies have indicated so far. For the boilers that can take burner modifications, the utilities feel that the cost estimate in the TBS report is a sound one.

However, for cyclone boilers, and perhaps top-fired boilers, there is great uncertainty about the availability and cost of controls. Some utilities are concerned that these costs could become even greater than SO_2 reduction costs at individual plants.

TBS's COST PROJECTIONS FOR KENTUCKY POWER ARE CONSERVATIVE FOR SCRUBBING, BUT ARE HIGH IF THE UTILITY COULD SWITCH TO LOW SULFUR COAL

The CRS critique focused on an analysis of costs for the Kentucky Power Company and based its conclusions largely on a finding that the TBS cost estimates for that company were greatly overstated. The criticism was two-pronged: first, that a compliance method (scrubbing) was chosen that is not optimal for this plant; and second, that the TBS cost estimate for scrubbing at that plant is too high even if scrubbing were required.

On the first point, one simply cannot predict with any certainty just what the states will require at individual power plants. Based just on the location of the plant in eastern Kentucky, and on its current fuel characteristics, the Big Sandy plant does look like a good candidate for coal switching rather than for scrubbing. In fact, preliminary indications from the utility company are that it would probably opt for coal switching under this bill if it has that option.

On the other hand, political factors may also play a role in the State's decisions about an appropriate compliance method at this plant. Kentucky Power is the only utility company out of seven in Kentucky with over 500 Mw of coal-fired capacity that has not installed a single scrubber. Furthermore, Kentucky Power is owned by American Electric Power (AEP) and sells a significant share of its electricity production to other states in the AEP system. It is possible that states could view situations such as this as opportunities to impose relatively strict compliance requirements, where at least part of the costs would be transferred to out-of-state customers and owners. With these factors in mind, the State could decide on a compliance strategy that is suboptimal for the individual plant but meets other political objectives.

If low sulfur coal switching were allowed at the Big Sandy plant, the TBS cost estimates would be within about five percent of the CRS annualized cost estimate, as explained later. If a scrubber were required, instead, then the cost that TBS estimated is conservative, compared to previous estimates by the utility company.

In November 1984, American Electric Power (AEP) compiled its estimates of the potential costs of acid rain control for a briefing to Moody's Investors Services, the organization that follows and evaluates the financial condition of large corporations and utilities and determines bond ratings on new debt issues. AEP's briefing covered three bills that had received widespread attention at that time: a revised version of the Stafford bill (S 768), the Sikorski/Waxman bill (HR 3400), and the Udall/Cheney bill (HR 5370). Different compliance strategies were estimated for the Big Sandy plant for each of the bills. For S 768, the compliance plan there was a scrubber on unit 2, 800 Mw. For HR 3400, it was fuel switching to low sulfur coal for both units 1 and 2, 1060 Mw. And for HR 5370, it was a scrubber on unit 2, 800 Mw, and fuel switching to low sulfur coal on unit 1, 260 Mw. These strategies provide a good basis for comparison with the range of scrubbing or switching strategies that could be utilized at the Big Sandy Plant under HR 4567.

The compliance strategy that was used in the TBS report for the Big Sandy plant was a scrubber on unit 2, listed in the EEI Power Statistics Database as 816 Mw, and no change at unit 1. For that strategy, we estimated an annual cost during the first five years of full compliance of $85 million and a rate increase of just over 30 percent.

The AEP annual cost estimate for S 768, which was the same strategy of scrubbing unit 2, was $150 million, almost twice as high as the TBS figure (levelized over the first ten years of compliance in 1984 dollars). Even the company's cost estimate for fuel switching, under HR 3400, was $60 million per year. Unfortunately, the CRS critique provides no figures for its estimate of annual cost, so a direct comparison is not possible (CRS results are only presented in terms of percentage rate increase).

The AEP presentation to Moody's also included estimates of potential rate increases. The projection for Kentucky Power under S 768 was 48.9 percent, which would imply about a 27 percent increase for the $85 million projection made by TBS in the current report. CRS's estimate for this same level of scrubbing, excluding costs for NOx control and replacement power, was 24.2 percent.

THE EXCLUSION OF INNOVATIVE TECHNOLOGIES IS CONSERVATIVE AND FITS THE SCHEDULE IN THE BILL

CRS sharply criticized the TBS report for not assuming that utilities would take advantage of the flexibility in the bill to utilize "innovative and cost-effective responses" to achieve the needed emissions reductions. The CRS document included a cost analysis of two innovative control strategies, LIMB (Limestone Injection Multi-Stage Burners) and Dry Scrubbing.

The bill, however, at least in its current form, does not really provide the states or utilities with enough flexibility to consider technologies such as these, which are not yet commercially proven. Section 181 of the bill requires the states to submit their specific plans, complete with emission limitations and compliance schedules for individual powerplants, to EPA within one year after enactment of the bill. That one-year schedule does not allow enough time to determine fully the commercial feasibility, performance, and cost of these or many other potential innovative technologies.

Even vigorous proponents of LIMB would have to agree that the technology will not be proven in the required timeframe. The CRS critique describes LIMB as "a developmental technology which would probably be available for commercial use by the late 1980s or early 1990s." A CRS report on LIMB in April 1985, indicated that "the technology is not sufficiently demonstrated for commercialization to occur." In that report, CRS projected that if EPA research continued at a strong pace, "it is reasonable to assume that commercial decisions about LIMB could begin being made by 1988 or 1989. If EPA's efforts are cut back as proposed by the Administration, this decision could be set back from a couple of years to several years. . . "(Parker 2, p. 14).

Dry scrubbing is further along the path to commercialization, and is characterized in the current CRS report as "a recent technology" and in last year's CRS report on LIMB as in the "early commercial" stage of technical development. This technology might be applicable to some plants within the timeframe of the bill, but there are drawbacks. The technology will not work effectively on high sulfur coals, and its cost advantage over wet scrubbing is much smaller than for LIMB, only about 20 percent annualized cost savings, according to last year's CRS report. To be conservative, we did not include dry scrubbing in our assessment of HR 4567, and instead assumed that only current, commercially available technologies could be considered within the bill's very short timeframe.

RESPONSES TO SPECIFIC CRITICISMS OF TBS'S METHODOLOGY AND ASSUMPTIONS

The CRS critique contained several specific criticisms or inferences which warrant direct responses by TBS. We have met and corresponded with CRS staff several times over the past eighteen months to compare our respective methodologies for this type of research. As a result, we would have expected that when they had additional questions they would simply contact us directly for clarifications and explanations of our assumptions and methodology. We were disappointed that that did not occur. Some of the most significant points that warrant clarification are summarized below.

- The TBS estimates are in mid-1986 dollars. For some reason, the CRS report contains the statement that "CRS assumes TBS's 1986 dollars are really end of 1985 dollars" (p. 11). We are not sure why that was assumed, but want to make it clear that all of our cost figures were inflated by 5 percent from 1985 levels to arrive at mid-1986 levels, since this currently is 1986.

- The TBS capital cost estimates for scrubbers are consistent with EPRI data. The CRS cost estimates for wet scrubbing were based on a unit cost ($235 per Kw) that is 16 percent lower than the estimate that TBS used ($280 per Kw). The TBS estimate is based on the average capital cost for conventional limestone scrubbers as reported in EPRI's "SO_2 and NOx Retrofit Control Technologies Handbook", of October 1985. The reported cost of $175 per Kw in 1982 dollars (EPRI p. 5-37) was inflated to 1986 and then scaled by a retrofit factor of 1.3, which is the same factor CRS used. It is interesting that in its report on LIMB last year, CRS reported a capital cost of $260 per Kw for wet scrubbing systems, in 1982 dollars.

- The TBS operations and maintenance costs for scrubbers are consistent with others, including estimates cited last year by CRS. The CRS critique made a point of TBS's estimate for variable operations and maintenance costs being almost 8 times higher than theirs (p. 8). However, CRS seems to stand alone in using such an estimate. The TBS estimates for O&M expenses are $13 per Kw for annual fixed O&M and 1.7 mills per Kwh for variable O&M (in 1986 dollars). ICF's estimates, listed in a February 1986 report for EPA, were a little over $10 per Kw and 2.0 mills per Kwh, respectively for a plant burning coal at 3.33 lbs/MMBtu of SO_2

(ICF 3, p. 3-4). Again, CRS's 1985 report on LIMB contained cost parameters much more consistent with TBS's--total O&M was listed as 6.4 mills per Kwh, which is consistent with a fixed cost of $13 per Kw, a capacity factor of 60 percent, and a variable O&M rate of 3.9 mills per Kwh, and that's all in 1982 dollars.

- TBS's unit costs for switching to low sulfur coal are reasonably close to CRS's. CRS described its coal switching cost assumptions in the context of switching the Big Sandy plant that currently emits just under 2.0 lbs/MMBtu of SO2 down to compliance coal (1.2 lbs/MMBtu). There is actually less difference between the estimates than is apparent, because the TBS methodology includes scaling both the fuel cost differential and the capital cost for switching to lesser values for plants that would switch from coals below the 3.0 lb. level. For the Big Sandy plant, CRS's unit cost estimates for coal switching were $10 per ton differential in delivered fuel cost and $10 per Kw in plant upgrading costs. TBS's unit costs for the same plant would be $9 per ton of the fuel cost differential and a one-time capital charge of $30 per Kw for the plant upgrade. The capital cost attributed to coal switching comes from the EPRI report referred to above and is based on a $45 cost per Kw for switching from an Illinois basin coal to a Central Appalachian one, which is the least expensive conversion according to EPRI's figures (EPRI, p. 2-7). On an annualized basis, the CRS and TBS costs for this plant would be within about five percent of one another.

- NOx control costs are included, but are conservative, in TBS's analysis. There is considerably less information available about NOx controls and control costs than there is for SO2. CRS in its critique decided that because NOx emissions at the Big Sandy plant are about .8 lbs/MMBtu, "it is not clear that the $10 a kilowatt low-NOx burners assumed by TBS in 75 percent of all cases would be necessary in this case" (p. 13). So they omitted any NOx control cost from the CRS analysis. It is not clear exactly how CRS expects the plant to achieve lower emissions, or whether they simply expect that the plant would benefit from reductions achieved at other plants in the state which would bring the statewide average down to the required level. The unit cost that TBS has used is taken from the EPRI October 1985 report referred to above, which reports capital costs for low NOx burners at $8 to $14 per Kw

(EPRI, p. 2-7). As mentioned earlier, however, there is substantial concern that NOx control costs at plants with cyclone boilers could be a great deal higher.

CRS'S OWN METHODOLOGY HAS A SIGNIFICANT DOWNWARD BIAS

One cost component in both the TBS and ICF analyses is for replacement power to run the scrubber's fans, reheaters, and pumps, and to compensate for the capacity derating that the scrubber causes at the unit. CRS has completely excluded this cost from its analysis. In the case of the ICF analysis, where relatively little scrubbing was forecast, this exclusion may not lead to a large cost difference. In the case of the TBS analysis, however, with 74 million Kw of scrubbing projected, the replacement power cost comes to about $0.7 billion of the $9.2 billion total annual cost of the bill.

The CRS rationale for excluding replacement power costs is that the short- and long-term reduction in demand due to the increased costs of electricity makes it unnecessary to replace this power. That logic might apply to the capacity derating, where the loss is simply the potential to produce electricity, and, because of reduced demand, that potential will not be needed as soon as it otherwise would. The logic does not apply, however, to the energy needed to power the scrubber and associated systems, because that does require incremental fuel to be burned and power to be generated.

More serious, however, is that CRS apparently wants to have it both ways--to use demand elasticity arguments to exclude costs like those for replacement power, but not to incorporate the increase in base rates that would be necessitated to compensate for such demand losses. Utilities are an extremely capital-intensive industry, and when demand goes down rates must go up so the revenue from the remaining customers will cover all the fixed costs.

CRS's long-term estimate of demand elasticity for electricity of 0.5 means that any utility that experienced a 20 percent rate increase would also experience a decline in long-term demand of 10 percent (20% x 0.5). If rates are unchanged, revenues would also decline by 10 percent. But approximately 40 percent of utility costs are fixed costs and would not decline when the demand did. As a result, the utility would need to raise revenues by an average of 4 percent to compensate for the loss in fixed cost coverage. If CRS is to use the demand elasticity argument to exclude costs on one front, then it must also use demand elasticities to scale up rate increase estimates to be consistent and complete.

OTHER CLARIFICATIONS

One point in the TBS report that has confused some readers is the use of the word "offsets" to describe future emissions reductions (p. 1). That was an unfortunate word choice, because this bill does not contain any requirement for emissions offsets as EPA's non-attainment policy does. The phrase had simply been intended to indicate that, as future electricity loads grow and coal plant utilization levels increase, the compliance actions taken to reduce emissions rates at those plants will have an additional, offsetting effect compared to where emissions would be without the bill.

ATTACHMENT

Utility Companies Evaluation of TBS Cost Estimates
(Based on informal contacts with the companies, this does not necessarily imply official endorsement of the TBS study by the individual companies)

Utility Company Commenting that TBS's Cost Projections are Close to Their Own Estimates

- Alabama Power
- Consumers Power (MI)
- Duke Power (NC)
- Georgia Power
- Illinois Power
- Kentucky Utilities
- Mississippi Power
- Pennsylvania Electric
- Pennsylvania Power & Light
- Public Service of Indiana
- Southwestern Public Service (TX)

Utility Companies Commenting that TBS's Cost Projections are Too High

- Florida Power & Light
- Iowa Public Service
- Kansas Power & Light
- Kentucky Power
- New York Electric & Gas
- Northern Indiana Public Service
- Wisconsin Power & Light

Utility Companies Commenting that TBS's Cost Projections are Too Low

- Appalachian Power
- Cleveland Electric Illuminating
- Columbus & Southern Ohio Electric
- Consolidated Edison (NY)
- Detroit Edison
- Indiana & Michigan Electric
- Ohio Power
- Potomac Electric (VA)

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Energy Ventures Analysis, Inc. "Evaluation of SO_2 Emissions and the FGD Retrofit Feasibility at the 200 Top Emitting Generating Stations." Prepared for U.S. Environmental Protection Agency, January 10, 1986.

Hall, H.M. "AEP System Economic Impact of Acid Rain Legislation." Presentation by American Electric Power Service Corporation to Moody's Investors Services, November 27, 1984.

ICF Incorporated. "Preliminary Analysis of H.R. 4567". Draft memorandum prepared for EPA, April 23, 1986.

__________________ "Preliminary Assessment of the Impact of Interest-Free Loans on the Economics of Retrofit Scrubber." Memorandum prepared for EPA, April 17, 1986.

__________________ "Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year 1.2 Lb. Sulfur Dioxide Emission Reduction Cases". Prepared for the Environmental Protection Agency, February 1986.

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Parker, Larry B. and Duane A. Thompson. "Acid Rain Legislation and the Future of the Eastern Low-Sulfur Coal Industry." Congressional Research Service, unnumbered report, April 6, 1984.

Parker, Larry B., John E. Blodgett, Alvin Kaufman, and Donald Dulchinos. "The Clean Air Act and Proposed Acid Rain Legislation: Can We Get There From Here?" Congressional Research Service Report No. 85-50 ENR, February 21, 1985.

Parker, Larry B. and Robert E. Trumbule. "Mitigating Acid Rain With Technology: Avoiding the Scrubbing-Switching Dilemma". Congressional Research Service unnumbered report, June 27, 1983.

Temple, Barker & Sloane, Inc. "Economic Evaluation of H.R. 4567, The 'Acid Deposition Control Act of 1986'." Prepared for the Edison Electric Institute, April 14, 1986.

The Chairman. Thank you very much.

Without making specific reference to a specific proposal, and I have not by this question meant to confine our consideration but to broaden our consideration to any proposal that might be made for a near term acid rain program that is aimed at immediate reductions in emissions, and immediate being within the next 5 or 6 years, we would make large reductions in emissions. What is the cost to the taxpayer? Excuse me. Let me rephrase that. What is the cost of that program if implemented? Mr. Addison?

Mr. Addison. The EEI had a study done by Temple, Barker, Sloan on the Waxman bill, and that study indicated that in the first 15 years of that bill it would cost our customers $110 billion.

The Chairman. Mr. Wooten?

Mr. Wooten. Are you looking for just the cost in that first 5 or 6 years?

The Chairman. No, the cost of starting the program that is intended to get to the near term reduction of sulfur emissions. Do not wait for new technologies, just start now and get it done. What is it going to cost?

Mr. Wooten. We are projecting that if you implemented the types of bills that we are talking about in these major 50 to 60 percent reduction types from utility emissions in the Eastern part of the United States, that all of the estimates run between $2 and $8 billion a year levelized, and so you are talking in substantial amounts of money to implement those programs.

The Chairman. Mr. High?

Mr. High. I do not have the figures for the industry as a whole, Mr. Chairman. We have taken a quick look at that, H.R. 4567 as far as TVA system goes, and to implement those capital costs could be anywhere from $2 to $3 billion, and ultimately the annualized cost for fuel switching and operation of scrubbers and that kind of flexibility would probably be in the neighborhood of $600 to $800 million a year

The Chairman. Mr. Hawkins.

Mr. Hawkins. The EPA and the Office of Technology Assessment estimates for House and Senate bills that are now pending contain estimates that range between $3 billion to $6 billion a year in annual costs as a fraction of total utility revenue requirements which are over $100 billion a year. That is 3 to 5 percent.

The Chairman. Three- to five-percent increase in current cost?

Mr. Hawkins. In total revenue requirements.

The Chairman. When you are talking about total revenues, are you matching those revenues to the systems that would incur the cost, or are you taking the total revenues for the total utility industry?

Mr. Hawkins. These are the revenues for the electric generation industry in the United States.

The Chairman. Well, how much would it cost if you confine the cost to the ones that are producing the emissions?

Mr. Hawkins. Well, utility system specific revenue requirements would be a larger fraction. There have been estimates of 10 to 14 percent by the Office of Technology Assessment.

The Chairman. You are presuming that there would be a kilowatt-hour tax or some equivalent of that, because obviously a hydrobased system is not going to make an investment for desulfurization, but in order to generate revenues from that system for desulfurization or emission controls, it would be a kilowatt hour tax, I assume.

Mr. HAWKINS. The contribution of hydro is a small enough fraction so that even excluding that from these calculations wouldn't change the percentage very much.

The CHAIRMAN. The point I am trying to make is to find out from you whether you believe it should be spread over the entire utility industry. First of all, let me ask that question.

Mr. HAWKINS. All right. That is an issue on which the environmental organizations, including the NRDC, have stated is not an environmental issue but rather a policy issue for the Congress, and we have supported bills that both spread those costs and supported bills that do not spread those costs, and that will continue to be our policy.

The CHAIRMAN. So you do not care one way or the other?

Mr. HAWKINS. We do not have a position as environmental organizations. As individuals, I am sure that we would all like to have our costs shared with everybody else.

The CHAIRMAN. Of course, I understand that. I am just trying to get at what is the potential cost, and you have made the comparison between the total cost of emission control under a bill similar to the House bill, but you spread it over the entire utility industry in your estimate, which would indicate to me that you favor spreading it over the entire industry. Now, if that is not correct, then what is the cost, if we don't spread it over the entire industry?

Mr. HAWKINS. I tried to answer that. The Office of Technology Assessment estimates indicate that even without the sharing requirements, that you would have 10 to 14 percent rate increases in the worst States.

Mr. ADDISON. Mr. Chairman, could I follow up on that?

The CHAIRMAN. Sure, Mr. Addison.

Mr. ADDISON. The study I suggested to you just a few moments ago made by Temple, Barker, & Sloan for EII, there are some companies that would have increases as much as 30 and even over 30 percent under the Waxman bill. I think that is a creditable study, and I would like to file a copy of it if I could with your committee.

The CHAIRMAN. We will receive it either for the record or for the file. Thank you very much.

It is suggested by several witnesses that the industry, the utility industry cannot bear, does not have the resources to pay the cost of simultaneous immediate emissions control and the development of clean coal technology, if I understand what we have been told. Mr. Hawkins, do you agree with that?

Mr. HAWKINS. I do not. Mr. Chairman, I think that to analyze that question you have to look at two things, resources for emerging technologies for meeting expanded demand and emerging technologies to deal with retrofitting existing plants in order to abate emissions. Now, on the question of expanding demand, the testimony has been that the utilities will in fact make whatever investments are necessary to meet demand. You expressed a concern, which I think is a valid one, about whether they might be a little late in responding, and we may have some rough passage there, but they will make the investments. Given that, the question is, will they make efficient investments or inefficient?

I think we have to assume that they are going to be sensible enough in looking at their capital needs to look at the advantages that emerging technologies provide as an alternative to reliance on conventional technologies.

The CHAIRMAN. I interrupt only to ask this question. I have some reservation. More and more utilities are being questioned by regulatory agencies about investments they make that are speculative. If they make an investment in a new technology and it works, fine and good. If they make an investment in a new technology that is either more expensive or does not work, more and more State regulatory agencies are saying that is the risk the stockholder should take, the ratepayer should not.

If you were a utility executive faced with that uncertainty, what would you do?

Mr. HAWKINS. I would try to persuade the PSC that first certain technologies were not as speculative as the PSC staff might feel they were, and rank order them in terms of their speculativeness. Second, I would try to persuade the PSC that there is no fee lunch here, that risks are going to be a substitute for higher electricity rates in the future.

The CHAIRMAN. If I were a utility executive looking at that risk and the way it has been applied recently, I would take the safe course, and the safe course to me would be to retrofit with the existing scrubbers, and to build proven technology because then I know I would not have to persuade that staff.

Mr. HAWKINS. You are addressing the second point, which I would also like to try to respond to your question on. I thought you were addressing the question of how should a company approach its needs for expanded capacity.

The CHAIRMAN. I was asking what you would do if you were the utility executive faced with that decision.

Mr. HAWKINS. On the second question of retrofitting, let us just take an example. The single technology that received the most attention in these DOE responses was sorbent injection or LIM. A year ago Kurt Yeager from EPRI testified that $60 million would be needed in total in order to adequately demonstrate LIM commercially on four applications. There are four applications, four LIM demonstrations included in the current proposals. It is not clear to me that anyone is saying they are going to pull back on those applications if Congress adopts this legislation. Those decisions are going to be committed to and negotiations concluded between now and October. I do not find it credible that the industry, whether pooling the resources through EPRI or otherwise cannot find a total of $60 million in order to prove out that technology.

The CHAIRMAN. Mr. Addison, your company is one of those that expressed an interest in the solicitations by the Department of Energy and then did not make a submission.

Mr. ADDISON. Yes.

The CHAIRMAN. Would you briefly outline why you decided not to make a submission?

Mr. Addison. Yes, I would be glad to do that, but I would like to respond to something Mr. Hawkins said first, if I may.

It is really interesting to me that somebody who has never had to try to persuade a Public Service Commission of anything believes that there is an unlimited pool of money that the customers are willing to pay.

He said he would try to persuade the Public Service Commission there is no such thing as a free lunch. He would have to persuade them of a hell of a lot more than that, if you will pardon my French, because the customers are skeptical and the PSC is skeptical.

There is a limited resource there, and I am telling you from experience in having done it that we cannot get the money to do both, regardless of what Mr. Hawkins says. I do not believe he has the experience to make the statement he made.

Now, let me answer your other question. We are interested in the proposals and in the money for clean coal technology. When we got right down the lick log, we took a look at our situation, and we are having the heaviest expenditures now on a year-by-year basis on new construction that we have ever had. For the last couple of years, this year and next year, our expenditures for new construction are running about $1.2 billion a year.

In addition to that, we are participating in the development of the atmospheric fluidized bed combustion project that is being managed by TVA that Dr. High mentioned at Paducah, KY. Also, we are very heavy contributors to EPRI.

We have a couple of very tough years ahead of us in looking to persuade some PSC's that there is no such thing as a free lunch, because we have some units coming on line, and we just really felt it would be imprudent for us to venture into it now.

The Chairman. Mr. Wootten.

Mr. Wootten. Yes, Mr. Chairman, I would just offer an example. We talked to utility hosts and were asked if we would be interested in participating in a program. In this case, it was a sorbent injection program. That was not a large amount of money, but as the utility got into it after the PON came out and looked at their financial condition, they had to withdraw. We had already committed; not just Peabody, but a number of coal companies and a number of other companies had committed to this project.

The utility just could not handle it, and it was not a large amount of money. We were talking, I think, in the neighborhood of a $30 million project, so that is how I think those are examples of how this can occur, that the utilities cannot do both things.

The Chairman. Mr. High, if TVA is called upon for immediate reductions on sulfur admissions and there is a vigorous application of an acid rain program, will that so absorb your revenues and available capital that you will not be able to invest in new technologies?

Mr. High. I do not believe it is a question of absorbing the resources for investment in new technologies as much as your ability to meet whatever requirements you make.

Our initial strategy is to switch fuel to low sulfur coal, and we would pay a premium for that, obviously. That question is difficult to answer in absolute terms, because we do not know exactly what that commitment would be relative to what money we would have to spend on new technologies.

We prefer to think of the new technologies as a timing problem as opposed to a resource problem, although money is as hard for us to come by as any other utility. I think we would pursue the two technologies that we have underway now, obviously, because we believe those are the ones that will be more pertinent to our system than any of the others that we could envision.

To say that switching fuel would take the resources away from that development and stretch that development out, I do not think I could absolutely answer that question. My opinion would be probably at this point no. We have already made a fair commitment to both of those technologies.

The CHAIRMAN. How much new capacity will your system require within the next 15 years?

Mr. HIGH. If we continue with the new construction and if we get our nuclear programs back on line, we do not anticipate needing new capacity until around the year 2000.

The CHAIRMAN. So you are dealing primarily with the issue of retrofit?

Mr. HIGH. Yes, sir, we are, and in fact that situation is what drove us back into the different technologies.

The CHAIRMAN. Gentlemen, thank you all very much for your testimony. There will be some written questions which we will submit for response to the record.

I appreciate your appearance and testimony this morning. That concludes this hearing. The committee will stand adjourned.

[Whereupon, at 12:20 p.m., the hearing was adjourned.]

APPENDIX II

RESPONSES TO ADDITIONAL COMMITTEE QUESTIONS FROM WITNESSES APPEARING JUNE 10, 1986

RESPONSES TO

QUESTIONS SUBMITTED TO

RICHARD E. DISBROW, PRESIDENT
AMERICAN ELECTRIC POWER COMPANY, INC.

HEARINGS ON

CLEAN COAL TECHNOLOGY AND ACID RAIN CONTROL
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

JUNE 10, 1986

June 30, 1986

Question 1

EPA Administrator Thomas, on behalf of the Administration, stated that,

> "we do not yet believe that the current state of knowledge can sustain any judgment with respect to the level of emission reductions needed to prevent or eliminate damage."

Do you agree with this statement?

Response

This statement is correct from two standpoints. First, it is not possible at this time to determine what level of reduction in acid deposition will result from a given reduction in emissions. The National Acid Precipitation Assessment Program (NAPAP) 1984 Annual Report to Congress states:

> "The National Program's research on processes at work in the atmospheric link between the emission of precursor pollutants and acid deposition is addressed in key questions:
>
> 1. What are the important chemical species and processes governing the formation of acid substances in the atmosphere, and how do they operate?
> 2. What are the most important meteorological processes governing the transport of acid substances and their precursors?
> 3. How do the processes of wet and dry removal operate and how does their relative importance change with distance from the source?
> 4. How can the processes of transport, transformation, and removal be modeled so that we can understand current and predict future deposition patterns?
>
> The answers will tell us which sources and/or source regions are most likely to affect specific receptor regions and which atmospheric pollutants cause acid deposition in those regions."

A year after this report was published, NAPAP is still attempting to answer these questions.

Second, there remains considerable uncertainty concerning the magnitude of environmental damage that may be occurring and, more important, how much acid deposition may be contributng to such damage. The environmental effect most closely associated with acid deposition is acidification of surface waters. It has been claimed that hundreds of lakes and streams have been acidified over the past few decades, principally, if not solely, because of acid deposition. However, the recent National Academy of Science report Acid Deposition - Long Term Trends states:

> "Based on comparisons of historical data on alkalinity and pH recorded in the 1920s, 1930s and 1940s with recent data for several hundred lakes in Wisconsin, New Hampshire, and New York, we find that many lakes have decreased in pH and alkalinity and many have increased in pH and alkalinity."

Furthermore,

> "Data on alkalinity of some lakes in New York, New Hampshire, and Wisconsin suggest that changes in alkalinity greater in magnitude than about 100 ueq/L can occur over time periods of about 50 years. Changes of this magnitude are too large to be caused by acid deposition alone and may result from other human activities or natural causes."

It is clear that many factors affect the surface water acidification phenomenon, and that it is premature to single out acid deposition as a primary, much less the only, cause.

A second environmental effect associated with acid deposition is forest decline and dieback. A great deal of scientific evidence, both in this country and Europe, points to widespread changes in the health of certain tree species and forest communities. Although it has been hypothesized that acid deposition is contributing to these changes, scientific opinion is now pointing towards other causes, particularly other gaseous pollutants such as ozone. This is a critical area of research in NAPAP as well as for the utility industry (through the Electric Power Research Institute (EPRI)). It will likely require more years of intensive research before a definitive cause-and-effect relationship can be established.

Question 2

EPA Administrator Thomas added,

> "this is true even for the area of greatest scientific understanding, sulfur emission and surface water acidification. In the area of the impact of acid deposition on forests, we have yet to determine if a cause and effect relationship exists."

Do you agree with this assessment of current knowledge?

Response

We are in agreement with this assessment, for the reasons given in the previous response.

Question 3

On the basis of current knowledge of the causes of acid rain, in your judgment, can we formulate a control strategy that will assure achievement of the intended mitigation of acid rain once the prescribed control investments have been made? In other words, can we determine what pollutants need to be controlled, the size reductions that are called for, where the reductions should take place, and over what time frame they should be implemented?

Response

It is our judgment that an attempt to formulate a control strategy to reduce acid deposition is premature even if it is assumed that a reduction is needed and will result in an environmental benefit. As indicated in the response to Question 1, NAPAP has identified a series of research areas to address the source-receptor relationship (i.e., what sources contribute to deposition at what receptor). An intensive program is in place, both in NAPAP and EPRI, to develop this relationship.

The first part of this program is development of a regional computer model that can be used to quantify the source-receptor relationship. The second part will be an attempt to validate this model by implementing an extensive air quality and precipitation chemistry monitoring network. This network is to be established by U.S. EPA and EPRI. The data collected in the network will be compared to the model predictions to determine the accuracy of the model. The results of this validation experiment should be available in three to four years.

Question 4

There has been considerable discussion of the need to place emphasis on the development of clean coal technologies with retrofit application. For example, the Special Envoys Report emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

EPA Administrator Thomas emphasized in his testimony that "the most important application category for the focus of clean coal technology development would be the coal-fired retrofit application." Do you agree?

Response

Yes, I agree with Administrator Thomas that retrofit applications should be given high priority by industry as it pursues the development and demonstration of emerging clean coal technologies in accordance with recommendations in the Special Envoys Report.

Question 4

a. In your judgment, does the DOE Clean Coal Technology program adequately reflect this need? Or does the program place too much priority on technologies applicable to new construction?

Response

It should be remembered that the DOE Clean Coal Technology Program was enacted into law prior to the Special Envoys Report. While many have attempted to draw linkages between the two, they were not developed in tandem. The DOE program was designed to apply to all types of coal, exploring a wide variety and family of technologies for different applications. It was designed to reflect the need for both retrofit and new generation technology demonstrations. The program envisioned by the Special Envoys was much more specific, focusing on high sulfur coal with emphasis on the retrofit market.

From what little we have learned about the proposals submitted to DOE in response to the Clean Coal Technology Commercial Demonstration Program, it does not appear that a large percentage of the proposals would be classified as retrofit demonstrations. Before one draws the conclusion that industry was not interested in retrofit applications, however, it is important to determine (1) whether the DOE Program Opportunity Notice (PON) contained requirements that effectively served as deterrents to the submission of retrofit proposals and (2) whether current acid rain proposals calling for emission reductions to New Source Performance Standards (NSPS) levels unduly discouraged control technology applications which, while effective, are not designed to achieve NSPS performance.

Clearly, the PON requirements were unexpected based on what the industry believed the Program to be when it passed the Congress last year. Specifically, requirements calling for proposers (1) to project the market penetration of their particular technology beyond their own systems; (2) to prepare a companion broad environmental impact analysis of their technology; and (3) to proceed despite the uncertainties associated with cost-sharing repayment, were all unexpected developments. Costs associated with preparing proposals in response to the PON are quite high. These up-front costs would essentially be the same no matter whether a proposal was a comparatively minor $10 million retrofit project or a major $200 million project which entailed a repowering or new generation technology. It seems to me that, because of the uncertainties referenced above, a number of utilities reluctantly chose to forego submitting project proposals.

In addition, there is considerable uncertainty associated with the impact of acid rain control proposals which call for emission reductions to levels far beyond the capability of even the most promising of the emerging clean coal retrofit technologies. I think it unlikely that any prudent utility would install a retrofit technology to meet an emission control target by a certain date, (e.g., 2.0 lbs. by 1993 in H.R. 4567) and then to retrofit that same plant again with a different technology several years later to meet a more stringent emission limit (e.g., 1.2 lbs. by 1997).

Question 4(b)

Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control? Should they be?

Response

To the extent that these emerging technologies are allowed to enter the marketplace by way of either existing regulations or those envisioned in any new control program, I see great potential in their ability to significantly reduce emissions in a much more cost-effective and reliable manner than current technology. However, as indicated in my testimony, the utility industry will not be in a position to pursue emerging new technology and at the same time comply with an acid rain program as envisioned in current proposals.

Question 5

Under what circumstances will life-extension result in reduced atmospheric emissions?

Response

Because plant life extension is a relatively new concept, efforts to describe the relationship of total emission loadings and life extension necessarily involve a significant element of speculation. Among the critical factors which are speculative are growth of electric demand; possible enactment of acid rain legislation; the number of new units that may be constructed in the future; and the ease or difficulty with which units may be life extended beyond a 40-year service life. Analysis recently performed by the EPRI indicates that life extension will likely not give rise to an increase in SO_2 emissions. Specifically, EPRI projects that 76% of the 185 GW of the pre-NSPS without SO_2 scrubbers be life-extended to 60 years without causing SO_2 emissions to rise above current levels.

The extent to which SO_2 emissions may decrease in conjunction with life extension will depend largely upon whether there are significant changes in applicable laws and regulations. Should acid rain legislation like H.R. 4567 be enacted, numerous powerplants will have to be retired or retrofitted with SO_2 and nitrogen oxide (NO_x) control equipment in order to continue lawful operation. (Fuel switching to lower sulfur coal is a compliance option for achieving lower SO_2 emission limits but not for new NO_x limits.) The determination to retire or retrofit will entail judgments concerning the cost-effectiveness of the two options. Should the unit in question be structurally and operationally sound enough to operate reliably during the period required to recapture the investment in SO_2 and NO_x controls, then the unit would be a likely candidate for retrofit and life extension.

Even without acid rain legislation, it is possible that EPA's present regulations could be construed to require new pollution controls as a prerequisite to authorization for life extension. EPA could interpret 40 C.F.R. § 60.15 ("reconstruction") in a sweeping manner, thereby raising the possibility that life-extended units will have to meet new source performance standards for SO_2, NO_x and particulate matter. While this sort of reading of the reconstruction rule could bring about emission reductions in concert with life extension, it could also render life extension uneconomic in many situations. Finally, EPA could adopt new regulations that specifically address life extension issues. Such rules could be structured to mandate pollution control requirements that are less onerous than NSPS and that are related to the duration of a particular life extension project. Such an approval would foster the development and deployment of retrofit technologies. Also, certainty of rate recovery is critical to widespread adoption of retrofit controls in conjunction with life extension.

Question 6

What is the potential that the types of clean coal technologies under discussion will be able to meet New Source Performance Standards?

Response

At this point, there are but a few new clean coal technologies which will, in their own right, be able to meet NSPS level of controls as defined by EPA. They are pressurized fluidized bed combustion, atmospheric fluidized bed combustion and the integrated gas combined cycle technology.

Question 7

Are the technologies being developed by the DOE clean coal technology program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?

Response

Since some of the "new plant" technologies under development or nearing demonstration will achieve NSPS and will incorporate more efficient conversion of coal to electric energy than today's pulverized coal boilers, it would appear that new regulatory requirements will not be required to speed their deployment. Among these technologies are pressurized fluidized bed combustion (which AEP hopes to demonstrate in its part of the Department of Energy's Clean Coal Technology Program), atmospheric fluidized bed combustion and various combined-cycle technologies. It is of primary concern that present regulatory programs not impede the demonstration of these emerging technologies. Specifically, the NSPS and the new source review requirements contained in Clean Air Act §§ 160 et seq. ("prevention of significant deterioration") should not be applied by EPA so as to inhibit new technology demonstrations. Assuming that demonstration occurs without difficulty, it appears that commercial usage will be likely since technologies like fluidized bed combustion combine greater thermal efficiency, the capability of modular construction and NSPS compliance.

A number of other emerging technologies are readily adaptable to retrofit use but are potentially limited in their application because they will not meet EPA's current NSPS for coal-fired boilers, 40 C.F.R. §§ 60.40a et seq, e.g., sorbent injection technologies, retrofittable partial scrubbing and advanced coal cleaning. The potential that plants which are candidates for these retrofit technologies may have to meet NSPS for SO_2 and NO_x, either as a result of acid rain control legislation, interpretation of existing regulations or promulgation of new regulations, would be a serious disincentive to the use of these cost-effective "partial" control technologies. What is needed is assurance to the industry that, once developed and installed at life-extended units, these partial technologies will not be deemed inadequate at some time in the future. EPA could fashion new rules directly addressing plant life extensions, that mandate control requirements less stringent than NSPS.

Question 8

Mr. Donald Bauer, on behalf of DOE, stated that performance testing of clean coal technologies under consideration by DOE generally will not be completed until the early to mid-1990s. He concluded with the observation that "if the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options." Do you agree?

Response

I agree absolutely. As I pointed out in my written testimony, the clean coal technologies which, like AEP's pressurized fluidized bed project, have reached the commercial demonstration stage, can be available for widespread use in the late 1990's if demonstrations are initiated promptly. While there is a conjectural possibility that clean coal technologies might be available for industrywide use to meet the 1997 "Phase II" SO_2 reduction requirement in H.R. 4567, the practical reality is that capital that might otherwise be devoted to new technology by the electric utility industry will be exhausted on the purchase of conventional SO_2 scrubbers or other costly efforts to comply with Phase I of H.R. 4567, which carries a 1993 deadline. Compliance with acid rain control mandates would result in postponing the broad-based development of these more efficient clean coal technologies--and the system reliability enhancement it would ensure--until well into the next century. To force continued use of current control technology by way of an acid rain control mandate would not only deprive the American public of the immediate benefits of technological advancement but would also constitute a wasteful misallocation of limited capital.

Question 9

One of the premises behind the Clean Air Act was that industry would gradually retire old facilities and replace them with new installations subject to "new source performance standards." Consequently, there would be a gradual improvement in air quality. In your judgment, has this occurred?

In asking this question, it is observed that EPA Administrator Thomas, commenting on plant life extension trends, stated that, "this postpones the rate at which new sources will replace existing sources, making New Source Performance Standards a less effective way of reducing overall emissions in the near or middle term."

Response

There is no question about the improvement of ambient air quality in the United States since passage of the 1970 Clean Air Act. Between 1973, the year in which the emission control requirements of the 1970 Clean Air Act were first evident, and 1983, SO_2 emissions nationally declined about 28%, even though this 10-year period also saw a 60% increase in the amount of coal consumed by electric utilities. (AEP joined in this effort, having reduced its systemwide SO_2 emission rate by a full 30% and total SO_2 emissions by 15%.)

Attributing this significant reduction to any one provision of the Clean Air Act is problematical. While the retirement of superannuated generating capacity with new units in compliance with the Clean Air Act's NSPS and PSD rules have had the effect of reducing total SO_2 emissions, utility compliance with state implementation plan (SIP) provisions governing existing sources also played a significant role in reducing emissions. For example, SO_2 emission reductions of about 650,000 tons have occurred in Ohio since 1975 largely as a result of compliance by existing sources with Ohio's SIP.

Therefore, while SO_2 reductions may not be primarily linked with NSPS, the more important point, from the perspective of the environment, is that SO_2 reductions have indeed occurred.

That the growth rate in electric demand has slowed considerably from the pace experienced in the 1960s may well be the primary reason that fewer new plants have come on line during the last ten years than was anticipated in the early 1970s. Other factors should also be borne in mind, among them the rapid escalation in the cost of new powerplants, up to the level $1,250-$2,000/kw, driven in significant part by the stringency of NSPS.

In saying this, we are not critical of the congressional policy requiring that "best technological systems of continuous emission reduction" be incorporated in new sources. Rather, we point out merely that setting NSPS at a stringent level, with the prospects of ever-increasing stringency, is a strong disincentive for retirement of any but the most inefficient existing units. Refurbishment of existing units, as part of the life extension process, has begun to appear more and more attractive as the cost of new units increases, both in absolute terms and in comparison to the costs of refurbishing existing units. The attractiveness of life extension seems likely to increase as the industry acquires experience with refurbished plants and if the costs of life extension prove to be attractive vis a vis new construction.

Even with a slowing in the growth rate of electric demand, the process of new sources coming on line has by no means come to a halt. On the AEP System, two 1300-MW coal-fired units meeting the 1971 NSPS have come on line during the 1980s, Mountaineer (1980) and Rockport Unit 1 (1984). Two more 1300-MW units, Rockport Unit 2 and Zimmer, are expected to be on line by the end of 1991.

A major impediment to the construction of new generating capacity is the need to demonstrate the prudence of such new capacity to state ratemaking commissions after a new plant is complete. Prudence of new construction involves the fundamental question whether the new capacity is needed to meet customer demands. Problems arise when state ratemaking commissions apply an unrealistic hindsight test in judging the prudence of a utility's decision to build, rather than to review the utility's judgment on the basis of the facts and growth projections available when the decision to build was made. Given the ever-increasing lead time between a utility's decision to build and the on-line date of a new coal-fired plant, a period of 6 to 8 and sometimes 10 years, change in economic conditions like those experienced in the late '70s and early '80s can make even the most careful and rational projections look foolhardy in hindsight.

Question 10

In your opinion, what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the various legislative proposals before the Congress? For example, is the electric utility industry likely to rely on extension of the life of existing facilities rather than their retirement and replacement with new facilities?

Response

In reviewing numerous acid rain control proposals that have been introduced in Congress since 1981, we have found that while there is a common thread that links all of them, i.e., a massive SO_2 emissions reduction requirement concentrated in such states as Ohio, Kentucky, Indiana and West Virginia, the plant-specific compliance measures that would be most cost-effective vary from bill to bill. The critical variables which dictate an optimum compliance strategy are compliance deadlines; the presence or absence of a scrubber retrofit mandate and cost-sharing provisions in the legislation; total tonnage of SO_2 that must be reduced; and suitability of existing plants for fuel switching or scrubber retrofits. In the absence of statutory language requiring one specific type of control measure, the choice of whether to rely on life extension in connection with fuel switching or control equipment retrofit--as opposed to retirement and replacement with new generating capacity--is dictated by the projected cost effectiveness of the various potential control measures.

Question 11

In your judgment, to what extent is industry's decision to extend the life of an existing facility influenced by regulatory policies? For example, as I understand EPA regulations, at a certain point the costs of retrofitting an existing facility become great enough that it runs the risk of being classified as a new one subject to New Source Performance Standards. Would you comment.

Response

Life extension is a relatively new concept, a product of the 1980s, so that any comment about the relationship of regulatory policies to life extension practices must deal in terms of what can be anticipated to take place in the future rather than what has already happened. It is safe to say, however, that regulatory policy will play a significant role in determining how frequently utility managers will choose life extension rather than constructing new capacity. New laws or regulations requiring that life-extended units meet NSPS for SO_2, NO_x or particulates would be a significant disincentive for life extension. In contrast, a regulatory policy that requires either no new controls or new controls less onerous than NSPS could be an incentive for life extension.

The current EPA regulation that appears to be most relevant to life extension, 40 C.F.R. § 60.15 ("reconstruction"), presents significant uncertainties. First, since the reconstruction rule was adopted more tnan 10 years ago, 40 Fed. Reg. 58418 (1975), EPA was not directly addressing life extension issues at the time of promulgation. Second, even though the rule may appear to cover life extension projects, its scope has not yet been the subject of a definitive judicial or administrative ruling. Finally, the rule is "all-or-nothing"--if a life extension candidate plant fits within the scope of the rule, pollution control equipment satisfying current NSPS for SO_2, NO_x and particulates must presumably be retrofitted at the plant. If, on the other hand, the plant falls outside the scope of the rule, then no new pollution control equipment would have to be installed.

Even though Administrator Lee Thomas has stated that life extension could have major implications for future levels of emissions, especially SO_2, he also testified on May 9, 1986 via written response to Rep. John Dingell, Chairman, House Committee on Energy and Commerce, that regulation of emission levels associated with life extension practices through broadening the scope of "reconstruction" as it appears in 40 C.F.R. § 60.15 could create severe problems:

> "We believe that the implementation problems associated with revising the definition of reconstruction could be severe. It is extremely difficult to clearly distinguish investments in plant refurbishment from ongoing maintenance. There does not appear to be any clear rationale for deciding how many years of such expenses should be considered relative to any threshold value defined as reconstruction. Any revised definition EPA might develop could simply encourage utilities to revise their plans, possibly in inefficient ways, to ensure that the threshold is not exceeded. For these reasons, we believe that, under existing law, the reconstruction provision would not be a particlarly [sic] effective means for addressing the emissions implications of life extension."

As has been pointed out previously, life extension need not--and probably will not--increase total SO_2 loadings.

It therefore is an economic approach that should not be discouraged.

Unwitting expansion of the reconstruction rule, either through legislation, new regulations or interpretation of existing regulations, could deter utilities from refurbishment since transgression of the none-too-clear line separating maintenance from reconstruction carries with it the requirement of meeting current NSPS, even at an aging power-plant. Thought should be given to substituting a fine-tuned approach for the present all-or-nothing approach to plant refurbishment. Cost-effective emission reductions, rather than NSPS-level scrubbing, could be incorporated into life extension. Calling for more moderate emission reductions has the doubly salutary effect of allowing continued use of still-functional units and, at the same time, obtaining a significant reduction from current emission levels. To be sure, there is merit in a policy that favors rather than impedes life extension, both from an economic and an environmental perspective. Life extension should be viewed as a practice that offers significant economic benefits to society and that can be structured to bring about significant emission reductions in a cost-effective manner.

Question 12

The Clean Air Act provides for an extension of compliance dates for facilities that propose to utilize new or innovative technologies to comply with emissions standards. In your judgment, has this authority been effectively implemented by the EPA?

Response

Our problems with the "innovative technological systems" provision of the Clean Air Act, § 111(j), concern the statutory preconditions placed upon the grant of "waivers" from NSPS under Clean Air Act § 111. In order for a § 111 waiver to be granted, it is necessary that the innovative technology not be "adequately demonstrated"; that there be a "substantial likelihood" that the innovative technology will outperform the technology mandated by NSPS (or that the innovative technology will at least equal the NSPS technology, at lesser economic, energy and non-air environmental quality costs); and that the waiver will last no more than seven years. Moreover, § 111(j) does not automatically exempt innovative technology applicants from the coverage of the Clean Air Act's "prevention of significant deterioration (PSD)" provisions, §§ 160 _et seq_. Among the requirements in the PSD program is that the owner of a new source apply "best available control technology" which is defined by Clean Air Act §169(4) to be at least as stringent as NSPS. Although it is possible that a new source incorporating innovative technology may avoid having to run the gauntlet of EPA's PSD permitting program, such a result is by no means assured. The EPA Administrator is given little discretion by the Clean Air Act to depart from the prolix and complex requirements governing the authorization to construct new sources.

Under these circumstances, it is difficult to criticize EPA's implementation of §111(j) but it is equally difficult to conclude that innovative technology waivers of NSPS have played a significant role in hastening control equipment development.

Question 13

What is the national average cost of FGD retrofit per kilowatt? And, what would be the cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements? What would be the differential cost between implementation of the above options?

Response

As stated in the report "Utility FGD Survey" dated July 1985,* the total installed electric generating capacity in the United States was 687 gigawatts (GW), as of December 1984, of which 43% was coal-fired. Therefore, the total United States coal-fired capacity was 295.4 GW. The same report indicates that, as of the same date, total controlled (scrubbed) capacity was 106.1 GW. Thus, the total uncontrolled coal-fired capacity was 189.3 GW.

In the report "Economic Evaluation of H.R. 4567" dated April 14, 1986,** the cost for retrofitting a coal-fired unit with a scrubber was assumed to be $280/KW. Therefore, to retrofit scrubbers on the 189.3 GW of uncontrolled coal-fired units in the United States is estimated to cost:

189,300,000 KW x $280/KW

= $53.004 billion

There are cost components not included in the TBS-assumed cost of $280/KW, such as interest on borrowed funds during construction, which are real and substantial costs, but difficult to estimate on a national average basis. In recent studies of the cost of retrofitting scrubbers on AEP System power-plants, the average cost derived was $370/KW. If this average cost is used as a basis to estimate the cost of retrofitting scrubbers on 189.3 GW of uncontrolled coal-fired units, the total estimated cost is:

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*Prepared by PEI Associates, Inc., under DOE Contract No. DE-AC01-82EP12067.

**Prepared by Temple, Barker & Sloane (TBS) for the Edison Electric Institute.

189,300,000 KW x $370/KW

= $70.041 billion

This is likely to be something of an overestimate, as the AEP System plants analyzed burn predominantly high-sulfur coal and, therefore, the use of wet/lime scrubbers only was assumed. On a nationwide basis, other, less capital-intensive types of scrubbers could be used for some units which would result in lower scrubber costs.

We do not have national cost estimates for emission-specific limitations so that we are unable to state the differential cost between universal scrubbing and other emission-specific controls.

Question 14

What, in your judgment, are the estimated costs of implementing proposed acid rain legislation? Would you indicate the sources of such cost estimates and whether you agree, or disagree, with such analysis?

Response

Even though H.R. 4567 was introduced less than 3 months ago, it has been the subject of several macroeconomic studies which indicate that national annual compliance costs will be measured in the billions of dollars. In an April 14 report, Temple, Barker & Sloane estimated that the annual cost of compliance with H.R. 4567 will be $9.2 billion (1986 $) for the first five years during which all of the bill's control requirements are in play, 1997-2001. (Temple, Barker & Sloane addressed H.R. 4567 as it was introduced on April 10, not as it was passed by the House Subcommittee on Health and the Environment.) In a preliminary report prepared by ICF, Inc. for EPA Administrator Lee Thomas' use in testimony on April 29 before the House Subcommittee on Health and the Environment, it was estimated that the SO_2 emission reduction requirement contained in H.R. 4567 would entail annual compliance costs ranging from $3.1 to $5.8 billion (1985 $).

We believe that these two reports largely corroborate one another in the sense that both fall within the same order of magnitude and are roughly equivalent. Since both are macroeconomic studies, their results are dictated by simplifying assumptions and fall prey to the inability of econometric models to account for site-specific factors and constraints that inevitably drive compliance costs. In particular, the macroeconomic studies fail to account for the full extent of NO_x control costs because these studies do not come to grips with the difficulty of controlling NO_x emissions from top-fired, cyclone-fired and wet-bottom boilers that were commonly built in the Midwest during the '50s and '60s.

Question 15

What, in your judgment, are the comparative roles of different source contributors of air pollution as contributing factors in acid precipitation? Would you indicate the sources of such information and whether you agree, or disagree, with such analysis?

Response

A number of precipitation chemistry monitoring networks have been operating in the United States and Canada over the past 5 to 10 years. These include the National Acid Deposition Program/National Trends Network, the Multi-State Atmospheric Power Plant Pollutant Study (MAP3S) Precipitation Chemistry Network, and the Utility Acid Precipitation Study Program. These programs have established an extensive, high-quality data base on the constituents of acid precipitation. This data base indicates that the constituents primarily include sulfate, nitrate, calcium, magnesium, sodium, chlorine, potassium and ammonium.

Identifying the sources of these substances is more difficult. On a general, large-scale basis it can be said that sulfate and nitrate are primarily from anthropogenic sources, and the remaining constituents are from a combination of anthropogenic and natural sources. Natural sources include soils, biogenic activity and sea salt. Anthropogenic sources include industrial activity, agricultural activity, road salting, and others. Pinpointing exact sources on a smaller geographic scale is not possible at this time, for reasons stated above.

Question 16

In your prepared testimony, you state that, "Current trends in the utility industry strongly suggest that new capacity requirements may not be built in time to meet projected capacity needs of the mid-1990s."

Later in your prepared testimony, you state that, "many utilities have canceled or abandoned the construction of large base load facilities and are now unlikely to undertake major new construction programs."

a. What, in your judgment, is the reason why your company, or the electric utility industry generally, is unlikely to undertake construction of new coal fired electric power generation to meet electricity demand in the mid to late 1990s?

Response

Considerable uncertainty exists with respect to demand growth in the 1990's. It is unlikely that utilities will embark upon a broad program of new construction unless there is some regulatory assurance that they will be allowed to recover costs. Increasingly, state regulatory agencies are conducting far-reaching prudency inquiries regarding the extent to which utility decisions (made 8-10 years ago in good faith and upon valid growth assumptions at the time) to build new capacity were in the best interests of the ratepayer. Substantial disallowances for costs not considered necessary by the states have already forced stockholders to bear substantial losses. Therefore, utilities are reluctant to commit to new capacity unless they have a high degree of confidence that state regulatory agencies agree, in advance, that new generation is necessary and cost recovery will be granted upon completion of projects, assuming that the projects are properly constructed. For many utilities, even this type of approach is a gamble.

There is no assurance that a state ratemaking commission's informal agreement today will not be questioned by the same agency when the facility is completed 8-10 years later. It seems to me that some form of "rolling prudency review" is necessary to assure that utilities which make commitments for new capacity are afforded cost recovery for expenditures incurred on behalf of the ratepayer.

Question 16

b. To what extent can increased electricity demand be satisfied by life-extension?

Response

Generating units traditionally have been considered as candidates for retirement when their service ages approach or exceed 40 years. Life extension measures may be able to prolong service lives of some units up to about 20 years. However, implementation of life extension measures may be technically or economically infeasible in some instances.

By 1995, more than 100,000 MW of U.S. capacity will be 30 or more years old. A substantial part of this older capacity, perhaps 50-75%, could be refurbished and retained in service to serve utility system load requirements, making it unnecessary to install an equivalent amount of new capacity.

Question 16

c. What other alternatives are available?

Response

As a broad proposition, America's electric needs in the 1990s and beyond will have to be met primarily by coal and nuclear power. In light of the difficulties facing nuclear power at present and the lead time that is associated witn nuclear construction, new nuclear capacity will not likely be initiated during the next two decades. Despite volatility in oil markets, increased use of petroleum products, which implies increased oil imports, to meet increasing electric demand in the near- and medium- term would only increase America's foreign trade deficit and would therefore not be in the national interest.

Accordingly, we are left with increased use of coal. Institution of appropriate life extension programs coupled with development/demonstration of more efficient, modular technologies, and supplemented by the construction of some new coal-fired generating capacity, is the strategy best calculated to meet the demands of the 1990s. Energy conservation efforts should, of course, continue to be diligently pursued. However, it is unlikely that a further reduction in energy demand through conservation will be a major factor.

Question 17

What is the motivation of your company, or the electric utility industry, for undertaking the development of new clean coal technologies, like atmospheric fluidized bed combustion, rather than simply relying on traditional boilers with scrubbers?

Response

One of the hidden costs of acid rain control legislation is its potential for "locking" the United States into existing technology for reducing SO_2 emissions, i.e., scrubbers. While scrubber technology has improved since the early 1970s, it is still highly undesirable, particularly as a retrofit technology. In addition to their very high capital and operating costs, scrubbers consume a significant amount of electricity in their operation, thereby reducing power plant net output. Also, due to scrubber malfunctions, the on-line availability of power plants is reduced. Many scrubber designs produce huge quantities of unusable calcium sulfate sludge as a by-product that gives rise to a serious waste-disposal problem. The capital commitments associated with a massive scrubber retrofit program--the inevitable consequences of drastic acid rain control legislation--would siphon off resources. These resources otherwise would be available to develop technologically and economically superior low-emitting technologies. Thus, the enactment of drastic acid rain-control legislation would result in freezing SO_2-emission-control technology at its present unsatisfactory level.

Question 18

In your prepared statement, you state that "accelerated development of promising technologies will increase the range of options for new plant construction which may be needed in the next decade and beyond."

a. In your judgment, are these technologies going to be able to meet new source performance standards?

Response

AEP believes that emerging clean coal technologies such as fluidized bed combustion processes, limestone-injection multistage burners and advanced clean-coal techniques should be encouraged and accelerated. It is important that they be available and in place should the acid rain studies, when completed, indicate that additional SO_2 emissions reductions are warranted. In our judgment, only those emerging technologies which are going to be able to meet--or exceed--NSPS either alone or in combination, are practicable for new construction applications. The examples given above all fall into that category. (For reasons that we have previously discussed, retrofit applications should not be required to meet NSPS.)

Question 18

b. Was your company's decision to proceed with pressurized fluidized bed development, rather than another technology, influenced by concern for compliance with new source performance standards?

Response

AEP's decision to proceed with combined cycle Pressurized Fluidized Bed Combustion (PFBC) was only partly influenced by that technology's ability to meet or exceed NSPS. Other influences in that decision were our strong belief that PFBC offers greater economy, higher fuel efficiency, and greater fuel flexibility compared with other promising technologies. These factors can help keep the cost of electricity to our customers from rising faster than they otherwise might, absent this technology.

Throughout the years, AEP has been an industry leader in developing high-efficiency power plants and our pursuit of PFBC is one more step in that direction.

Question 19

In your prepared testimony, you state that among the submittals under the DOE Clean Coal Technology Program there are few retrofit projects.

a. What, in your judgment, are the reasons for this?

Response

As indicated in response to Question 4(a), we have not had an opportunity to review DOE project proposals (other than the public abstracts). However, it seems clear that many of the utilities that had expressed interest in submitting proposals in response to DOE's December 1984 Informational Solicitation, chose not to submit projects under the PON. A variety of factors may have entered into a utility's decision to forego a project proposal. For projects that fall into the retrofit area, costs associated with these requirements, such as those related to proposal preparation, may have led proposers to conclude that there were simply too many uncertainties to justify the cost of a project submittal. Three PON provisions in particular come to mind.

COST-SHARING

When the PON was issued by DOE, it contained language on cost-sharing which was dramatically different from any portion of the Congressional debate on the Clean Coal Program. The Clean Coal Technology Coalition followed this debate closely. At no time during the debate was cost-sharing characterized as a loan. Cost-sharing was therefore interpreted by industry to be a government grant. The final PON required that project sponsors repay the government out of net profits that might be derived from a project following "the period of performance." For a regulated utility, the repayment provisions posed significant uncertainty relating to a state commission's decision to allow repayment. There is no assurance that a state would allow a utility to repay the federal government when, in the opinion of the state, the state's ratepayers were assuming risks for a portion of the demonstration project. The state might logically conclude the federal government should also assume risks regardless of the outcome of the project.

As an example, if the project proved to be successful, the state could take the position that, while its ratepayers benefited, so would ratepayers in another state if a utility in that state ultimately deployed the demonstrated technology. Therefore, the federal government share in a project could be interpreted as a contribution or a sharing of risk on behalf of ratepayers in all states. If the state disallowed DOE's portion of the project in rate base, the stockholder would be asked to repay the federal government. This provision may have served as the most significant deterrent to utility submission of proposals for any type of project.

MARKET ANALYSIS

Project sponsors were also required to prepare market analyses which reflected the extent to which the proposed technology would be absorbed in the commercial marketplace. For the average electric utility project sponsor, a request for information of this nature would be considered especially difficult to prepare and document. Utilities are not in the business of assessing the likely market penetration of a particular technology. (Equipment manufacturers might well be better situated to comply with this provision.) For a utility, it is unlikely that it would have the necessary supportive data base to assess a market for a given technology beyond the needs of its own individual system. The costs associated with sucn an analysis could run high.

ENVIRONMENTAL ANALYSIS

A similar difficult requirement to comply with involved the preparation of broad-scale environmental analyses of the likely impacts of the proposed technology. Again, from a utility perspective, it would be very difficult to assess the impacts of a particular technology outside a given utility's own service area. Moreover, the costs of preparing such environmental analyses would be high.

Question 19

b. In your opinion, is the program responsive to the recommendations of the Joint Envoys Report on Acid Rain regarding the need for development of retrofit technologies?

Response

Please refer to my response to question (4a).

RESPONSE OF JOHN L. McCORMICK

ENVIRONMENTAL POLICY INSTITUTE

TO QUESTIONS SUBMITTED BY

SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

PERTAINING TO THE CLEAN COAL TECHNOLOGY RESERVE HEARING

JULY 2, 1986

1. Question

E.P.A. Administrator Lee Thomas testified that,

" we do not yet believe that the current state of knowledge can sustain any judgement with respect to the level of emission reductions needed to prevent or eliminate damage."

Do you agree with this statement?

1. Answer

The uncertainty with respect to the level of emission reductions needed to prevent or eliminate damage from acidic precipitation in the U.S. and Canada, will have to yield to the politics of the issue. There will be a resolve of this transboundary air pollution problem and, very likely, the outcome will be determined in the 100th Congress. Thus, Administrator Thomas should give higher priority to eliminating those uncertainties quickly.

The weight of scientific judgement has already shifted towards control of existing sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions. The targetting of specific sources and actual tonnage reductions may require further refinement but the public on both sides of the border are ready to move the question of acid rain control. Special Acid Rain Envoy Drew Lewis stressed both the diplomatic and environmental problems acid rain has caused between the U.S. and Canada. EPA Administrator Thomas may have doubts about the "level of emission reductions needed" but he cannot continue to doubt that reductions are needed.

Canadian scientists have concluded both countries must agree to limit SO2 emissions sufficient to assure no greater than 20 kilograms of wet sulfate deposition per hectare per year (20 kg/ha-yr) to protect Canada's most sensitive aquatic ecosystems.

If precise measurements of the effects on a particular ecosystem when SO2 emissions are reduced from a targetted source were the basis for making a decision on acid rain control, it is likely no action would occur. The science of source - receptor measurements is influenced by as many as 19 separate chemical reactions and innumerable atmospheric and terrestrial variables.

The Office of Technology Assessment report, Acid Rain and Transported Air Pollutants stated:

> "Acid deposition results from both local and distant sources of SOx and NOx. Current scientific understanding suggests that reducing sulfur dioxide (SO2) emissions throughout the Eastern 31-State region would reduce the deposition of acid-producing substances; but that this will occur in the areas sensitive to acid deposition cannot be stated with certainty."

In the East, approximately two-thirds of the acid deposited results from sulfur compounds. They become acid when they oxidize either in the gas phase; after absorption into water droplets; or after being deposited as dry deposition on the ground. The rate of coversion of SO2 to sulfate depends on the chemical composition of the atmosphere. SO2 oxidizes more readily when there is not a saturation of oxidant-seeking pollutants such as NOx and radical hydrocarbons.

Dry deposition is believed to occur at a fairly constant rate over time while wet deposition is eposodic and may vary in concentration within a rainfall event.

Natural sources of sulfur emissions contribute less than 5 to 10 percent of total national emissions. Thus, man-made sources of SO2 emissions dominate the national total of 26 million tons (1980 estimate) and, of that amount, 22 million tons originate in the Eastern 31 States.

Similarly, natural sources of NOx appear to contribute less than 15 percent of total NOx emissions in the Eastern U.S. National NOx emissions in 1980 totaled 21 million tons, of which 14 million tons originated in the Eastern 31 States.

NOx reacts with sunlight and hydrocarbon-produced radicals (RHC's) to form ozone. Ozone has been observed, both in laboratory tests and in the field, to damage vegetation by affecting a tree or plant's photosynthetic process.

Both ozone and nitric acid formation involve RHC's. The gas phase reaction leading to nitric acid occurs about 10 times faster than the corresponding reaction with SO2. Thus, nitric acid formation and depostion likely occur closer to the source than sulfuric acid deposition. SO2, therefore, travels longer and farther before being deposited as wet or dry deposition.

This analysis presents certain choices regarding the type, amount and targetted area for emission reductions. The availability of NOx and RHC's in the atmosphere removes oxidants which, otherwise, will convert SO2 to sulfates. However, distance and time may overcome the oxidant shortage for SO2 in a particular region.

Since twice as much sulfate as nitrate is present in rainfall, it would appear that reducing sulfate deposition might be the most likely way to begin reducing acidic deposition. And, field tests measuring greater amounts of sulfuric acid leaving a water shed than entered from a rainfall event indicates that collected dry gases and particles also contribute to the acidic inflow to a lake or stream. The demise of aquatic ecosystems subjected to high hydrogen ion concentrations have been well observed in the field and studied in controlled conditions.

Canada's scientists are convinced that SO2 and NOx pollutants, from both sides of the border, are causing serious and possibly irreparable harm to its aquatic and forest ecosystems.

On August 5, 1980, Canada and the U.S. signed a Memorandum of Intent (MOI) on transboundary air pollution. It established a Co-ordinating Committee to negotiate a collective agreement on transboundary air pollution.

Both the U.S. and Canadian members of the Technical Work Group agreed that, for North America:

> "There have been no reported chemical or biological effects for regions currently receiving loadings of sulphate in precipitation at rates less than about 20 kg/ha-yr. Evidence of chemical change exists for some waters in regions currently estimated or measured to be receiving 20-30 kg/ha-yr sulphate in precipitation....Long-term chemical and/or biological effects and short-term chemical effects have been observed in some low alkalinity surface waters experiencing loadings greater than about 30 kg/ha-yr."

The report issued by the Impact Assessment Work Group had a Canadian and a U.S. version. The Canadian version recommended a maximum level of 18 pounds of wet sulfate depositon per acre per year to protect all but extremely sensitive aquatic ecosystems. Separate Canadian/U.S. peer reviews of the reports were conducted. In July, 1983, the Canadian Peer Review Report concluded that scientific evidence was sufficient to warrant a major program of air pollution abatement.

The Lewis-Davis Report of the Special Acid Rain Envoys concluded that:

* "acid rain is a serious environmental problem both in the United States and Canada. Acidic emissions transported through the atmosphere undoubtedly are contributing to the acidification of sensitive areas of both countries. The potential for long-term socio-economic costs is high."

* "Acid rain is a serious transboundary problem. Air pollutants emitted by sources in both countries cross their mutual border, thus causing a diplomatic as well as an environmental problem."

The U.S. cannot continue to refuse to negotiate an acid rain solution with Canada; particularly in light of the fact that the Province of Ontario announced on December 7, 1985 its commitment to a very expensive air pollution cleanup effort. Ontario Premier David Peterson's ambitious program requires the Provinces's four main producers of acid rain-causing SO2 to reduce their emissions from the 1980 level of nearly 2 million tons to a maximum of 665,000 tons by 1994. That is a reduction of 67 percent.

Its overall cost is estimated to range between $1.5 and $2 billion but the program will have negligible impact upon Canada's acid rain problem if the U.S. refuses to take similar action. On average, every ton of SO2 that falls onto Canadian territory comprises half a ton that originates in Canada and half a ton in the U.S. Unlike the dangers of exposure to trace amounts of toxic air pollutants, acid rain damage is caused by continuous exposure to high concentration levels. When Canadian scientists determine that 18 pounds of wet sulfate depositon per acre per year is the highest "acceptable" level to protect sensitive areas, reducing concentrations down to 25 or 20 pounds is not a remedy at all. Therefore, a unilateral reduction plant will not offer sufficient protection.

In a January 22 address to the New York Board of Trade, the Honorable Tom McMillan, Canada's Minister of Environment, stated: "If Canada were to eliminate every particle of sulfur dioxide and oxides of nitrogen from Canadian sources, it would be able to do nothing more than cut acid rain overall by half. In some of the most affected areas, however, that cut would not be enough to stem the damage being done."

He also pointed out to the U.S. audience that Canadians see the acid rain issue as "a litmus test of whether Canadian-U.S. cooperation works both ways". The U.S. and Canada are the most active trading partners in the world. According to the Environment Minister, "...we buy more of your goods than any other nation on earth -- Japan included. In fact, Ontario alone, just one of our 10 Provinces, buys more from the U.S. than does all of Japan"

2. Question

E.P.A. Administrator Thomas added,

"this is true even for the areas of greatest scientific understanding, sulfur emission and surface water acidification. In the area of the impact of acid deposition on forests, we have yet to determine if a cause and effect relationship exists."

Do you agree with this assessment of current knowledge?

2. Answer

The relationship between sulfur emissions and surface water acidification is well understood. In fact, U.S. and Canadian scientists agreed, in the U.S. - Canadian Memorandum of Intent on Transboundary Air Pollution that:

> "There have been no reported chemical or biological effects for regions currently receiving loadings of sulphate in precipitation at rates less than about 20 kg/ha-yr. Evidence of chemical change exists for some waters in regions currently estimated or measured to be receiving about 20-30 kg/ha-yr sulphate in precipitation."

The only conclusion one can draw from that scientific statement is the need to assure that levels of acidic deposition be reduced to, or below, 20 kg/ha-yr.

With regard to the impact of acid deposition on forests, silvicologist, botanists and forest pathologists, both in the U.S. and West Germany are observing some very disturbing trends in forests on both continents.

West Germany foresters, known for their careful management practices, have measured alarming rates of forest-dieback since 1980. The likely causes such as drought, blight and heavy frosts have not been prevalent during this four year period of inventory when the areas of affected trees increased from 8 to nearly 50 percent of West Germany's forested lands.

A total of 18 regional declines of forests have been occurring in Europe over the past 200 years and in North America for at least the past century. This most recent forest dieback observed in West Germany is considered the most important of all regional declines of forests observed during the past century. It is the first multiple-species decline of forests reported in either Europe or North America.

Scientists on both continents are trying to limit the list of probable causes of forest decline by isolating each of the components of the hypotheses that have been offered. There is evidence of a synergistic demise of European forests and most scientists point to pollutant aerosols as the primary cause. Trees exposed to prevailing winds, either because they stand above the forest canopy or are on the edge of the forest or open areas appear to suffer more damage than smaller and more sheltered trees.

Heavy metals uptake in fine root hairs of trees deprive the flow of nutrients from the soil. That is prevalent in some of the more damaged forests of West Germany and is indicative of high concentrations of hydrogen ions which mobilize aluminum in the soil.

Ozone damage to vegetation has been observed and understood for many years. The demise of the Ponderosa Pine forests of the San Bernadino Forests, east of the Los Angeles Basin has been scientifically linked to the high concentrations of ozone in that air shed where SO2 emissions are not significant.

Nitrates from oxidation of fuel-burning NOx emissions and use of agricultural fertilizers are known to artifically stimulate growth of trees during periods of dormancy. This inducement to growth during cold months can severely stress vegetation.

The precise pathways the various pollutants, heavy metals and growth-inducing organic compounds take to weaken and kill vegetation must be identified. However, ozone-forming aerosols have been researched enough to convince the West German government that it must act quickly to reverse the forest dieback disaster.

Trees have natural immune and buffering systems to overcome normal abuses of drought, insects, frost and other impacts. However, there is a growing concern that those systems can be stressed beyond their adapted ability to cope. Whether the alarming rate of forest dieback witnessed in West Germany's forests since 1980 is a manifestation of the forests' succumbing to the combined effects of acidic rain and ozone has not yet been established. But, this theory points to the gravity of the problem because it indicates the residual impacts of aerosol pollutants long after their concentrations in the air shed have been diminished.

In North America, similar evidence of forest dieback is being recorded among several important commerical species, particularly red spruce in the East. All the evidence gathered on both continents that points conclusively to the causes of forst dieback may have little value if the demise of North America's maple, spruce, birch and pine forests are found to be irreversible. There is sufficient understanding of the high concentrations of acidic deposition in clouds and fog to link the dieback of tree stands along the ridgetops of mountains to justify reduction of SO2 emissions. And, the science of ozone impacts on vegetation has been established for more than a decade.

The time-related problem of air pollution and vegetative damage in North America requires the reduction of SO2 and NOx emissions quickly because Germany may have discovered the cause of its forest dieback too late to react.

3.(a) Question

On the basis of current knowledge of the causes of acid rain, in your judgement, can we formulate a control strategy that will assure achievement of the intended mitigation of acid rain once the prescribed control investments have been made?

3(a) Answer

If the U.S. bases an acid deposition control stratgey upon the need for total certainty regarding source-receptor relationships, the time delay will be unacceptable.

According to the OTA Report:

> "Very specific source-receptor relationships cannot be defined unless the behavior of all other pollutants is known. Given the complexity of the atmospheric chemistry alone, as well as the need to develop

> detailed emissions inventories (especially for NOx and RHC) and the inherent meteorological variability, it is unlikely that a definitive model integrating SO2, NOx and RHC will be developed in the next decade or two."

This does not infer that sufficient data and scientific understanding do not now exist to warrant the implementation of an SO2 and NOx emission reduction program.

The NRC/NAS, *Atmosphere-Biosphere Interactions: Toward a Better Understanding of the Ecological Consequences of Fossil Fuel Combustion*, published in 1981, concluded:

> "Of the options presently available only the control of emissions of sulfur and nitrogen oxides can significantly reduce the rate of deterioration of sensitive freshwater ecosystems. It is desirable to have precipitation with pH values no lower than 4.6 to 4.7 throughout such areas, the values at which rates of degradation are detectable by current survey methods. In the most seriously affected areas (average precipitation pH of 4.1 to 4.2), this would mean a reduction of 50 percent in deposited hydrogen ions."

According to the OTA Report:

> "Available knowledge of atmospheric chemistry suggests that if: (1) there is no shortage of oxidizing agents (i.e., saturated conditions do not prevail); (2) levels of RHC and NOx remain constant; (3) deposition processes and meteorology remain constant, reducing SO2 emissions will reduce the total amount of acid formed in the atmosphere. Furthermore, given these conditions, a decrease in SO2 emissions should decrease the atmospheric formation of sulfuric acid by an approximately equal proportion."

Finally, the National Academy of Sciences 1983 report, *Acid Deposition: Atmospheric Processes in Eastern North America*, concluded that:

> "...on the basis of analysis of currently available data in eastern North America and within the limits of uncertainty associated with errors in the data and in estimating emissions, we conclude that there is no evidence for a strong nonlinearity in the relationships between long-term average emissions and deposition."

3(b) Question

Can we determine what pollutants need to be controlled, the size reductions that are called for, where the reductions should take place, and over what time frame they should be implemented?

3(b) Answer

The effects of wet and dry sulfate deposition upon unbuffered and poorly buffered aquatic ecosystems have been quantified in numerous controlled and uncontrolled observations. Entire watersheds have been monitored for concentrations of acidic input and resultant demise of aquatic vegetation and marine organisms.

The runoff from snowmelt has been observed to cause an acidic "pulse" which can overpower acid-neutralizing soils and shock spawning fish sufficient to prevent the reproductive cycle or kill the eggs and newborn. Lakes undergoing acidification exhibit predicatable stages of deterioration and each succeeding phase compounds the degradation of the ecosystem by threatening the food source of higher feeding organisms. Gradually, the lake becomes a sterile and uninhabited water body taken over by sphagmun moss and like organisms which signal its death.

4(a) Question

There has been considerable discussion of the need to place emphasis on the development of clean coal technologies with retrofit application. For example, the Special Envoys Report emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

EPA Administrator Thomas emphasized, in his testimony, "the most important application catagory for the focus of clean coal technology development would be the coal-fired retrofit application."

Do you agree?

4(a) Answer

The legislative history of the Clean Coal Technology Reserve describes its evolution from a program designed to promote the use of more coal to a federally funded research effort to burn coal more cleanly. Though the House and Senate Appropriations Committees may have focused more attention on one or the other goal, leading House advocates for acid rain control had a specific purpose in mind when they voted to support the program at a critical moment.

In their "Dear Colleague" letter (prior to the vote on the FY86 Interior Appropriations bill) House members Waxman, Sikorski, Walgren and Markey saw the CCTR as, "an important step in our efforts to reduce damage associated with acid rain emissions. As reported by the House Appropriations Committee, the Clean Coal Reserve will support, on a 50-50 cost shared basis with the private sector, demonstrations of advanced technologies which reduce both SOx and NOx emissions and promise to burn coal more efficiently."

The first $400 million provided the CCTR may not be sufficient to commercially demonstrate the many types of emission reduction retrofit technologies identified in the first DOE solicitation. An additional $350 million has been authorized for the program. However, the environmental legislators - the CCTR's swing votes in the House - must be convinced the money is being spent on those types of demonstration projects. If they are not satisfied with the product of the $400 million outlay, they have no reason to support more funding for a program that ignored the real problems in the coal and electric utility industries.

Senate Report 99-141, the FY86 Interior Appropriation bill included the following provision:

> "Earlier project selection criteria which were contained in Senate Report 99-82 on the fiscal year 1985 supplemental appropriations bill and which were modified in the statement of the managers, House Report 99-236, continue in force."

S. 99-82 provided the following general project guidelines:

1. demonstrate commercial feasibility at commercial scale;

2. do not duplicate commercial scale demonstrations currently being conducted in the U.S.;

3. technology must result in emission levels complying with Clean Air Act in a cost-effective manner;

4. technology should be commercially available no later than the 1990's;

5. 50-50 cost sharing between federal and private sector;

6. proper engineering, construction, design and operation assurances.

H.R. 99-236 reaffirmed those guidelines and further stated that the commercial application of clean coal technology for retrofit applications on fossil fuel-fired plants is likely to result in reduction of emissions from the use of coal at a cost which is competitive with the cost of achieving comparable emission reductions by current technology.

4(b) Question

In your judgement, does the DOE Clean Coal Technology Program adequately reflect this need? And, does the program place too much priority on technologies applicable to new construction?

4(b) Answer

The DOE's Program Opportunity Notice was not explicit with regard to an emphasis on emssions reduction retrofit technology proposals or any particular technology for that matter. Its non-specific guidelines may have been intended to encourage all types of technology sponsors to apply.

The real test of the Program's adequate reflecting the wishes of the Congress to demonstrate emission reductions retrofit technologies is the final list of accepted proposals which the DOE must submit to Congress prior to final contract agreements. We reserve judgement on the direction the CCTR is taking until the Congress has the opportunity to comment on that list of chosen technologies.

The CCTR was not designed to promote, nor has the DOE management shown any bias towards, technologies applicable to new construction. Among the CCTR proposals, several are demonstrations of technologies that may have to meet federal New Source Performance Standards rather than S.I.P. requirements of the Clean Air Act. However, the new construction proposals will be judged in accordance with selection guidelines that do not appear to be weighted towards any technology, retrofit or new construction. Again, the success of the CCTR can only be determined after the commercial demonstration of those technologies which meet the goals of the critical swing votes in both the House and Senate.

4(d) Question

Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control and should they be?

4(d) Answer

When the CCTR was initially drafted, it contained few, if any, guidelines and appeared to promote the use of more coal than the use of coal more cleanly. After negotiations with Senate Interior Appropriations Subcommittee staff, industry representatives and public interest organizations, the measure was improved significantly. The priority for the CCTR shifted from a coal utilization program to one that stressed environmental protection.

However, industries such as ore smelters and metals foundaries have environmental control problems that are not as easily resolved as are those facing the electric utility industry. The CCTP can accommodate proposals from sponsors intent on demonstrating more efficient and cost-effective technologies applicable to steel, copper, paper, fertilizer manufacture and other industrial processes. If their proposals fall within the DOE guidelines for project selection, they can qualify for cost shared funding. We recognize the continuing need to curb increasing U.S. dependence upon foreign sources of fuels and view the CCTR as having an important role to play in that important endeavor.

5. Question

Under what circumstances will life-extension result in reduced atmospheric emissions?

5. Answer

The electric utility industry trend towards keeping older boilers on line much longer than normal book-life of the equipment may represent a savings to consumers but it also cancels an important goal of the Clean Air Act. It was presumed, in 1975, that these older units would retire and be replace with N.S.P.S.-regulated equipment; thus assuring continued improvement in the nation's air quality.

In "Extended Lifetimes For Coal-Fired Power Plants: Implications For Air Quality Analysis" published in the May, 1986 issue of Public Utilities Fortnightly, Schwengels, De Mocker and Greenwald stated the following:

> "Sensitivity analyses of recent EPA emission projections have shown that changing the assumed retirement age from 45 to 60 years results in an increase in total emissions of sulfur dioxide (SO2) of 4-6 million tons in the year 2010. This change in projected emissions has significant environmental and regulatory implications."

This projected SO2 increase can be significantly diminished if the Clean Air Act, individual States, or the E.P.A. requires powerplants operating beyond a certain lifespan to limit SO2 emissions as a condition of continued operation.

The EPA is taking a close look at the air quality impacts of boiler life extension and the effects of imposing tighter emission regulations on boilers operating beyond thirty years.

6. Question

What is the potential that the types of clean coal technologies under discussion will be able to meet New Source Performance Standards without the use of scrubbers?

6. Answer

Not all of the projects submitted to the CCTR can provide SO2 emission controls sufficient to comply with current NSPS requirements. However, some address multi-pollutant control at costs comparatively lower than flugas desulfurization. Those technologies will make it easier and less expensive for the electricy utility industry to comply when the reauthorized clean air law mandates huge SO2 and NOx emission reductions for non-NSPS boilers. Examples of pollution control efficiencies of these technologies are provided in the following Table:

SUMMARY OF TECHNOLOGIES FOR POLLUTION CONTROL

DESCRIPTION	REMOVAL EFFECTIVENESS	AVAILABILITY
PHYSICAL COAL CLEANING	10-30% SO2	current
CHEMICAL COAL CLEANING	up to 90% SO2 25% energy penalty	post-1990
FLUGAS DESULFURIZATION	60-95% SO2	current
LOW EXCESS AIR/STAGED COMBUSTION	20-35% NOx	current
FIRST GEN. BURNER TECH.	40-50% NOx	current
2ND GEN. BURNER TECH.	50-70% NOx	1998
REBURNING TECHNOLOGY	50-80% NOx	post-1990
FLUGAS DENITRIFICATION	90% NOx	1990
ELECTROSTAT PRECIPITATOR	99.5% particulates	current
FABRIC FILTER	99.5% particulates	current
2 STAGE ELEC STAT PRECIP	99.5% particulates	1990
ELECSTAT ENHANCEMENT OF FABRIC FILTER	99.5% particulates	1990
LIMESTONE INJECTION/ MULTISTAGE BOILER--LIMB	retrofit 50-60% NOx & SO2 new- 70% NOx & SO2	1989
FLUIDIZED-BED COMBUSTION	90% SO2 - NOx ?	post-1990
E-SOX	50-80% SO2 99% particulates	1990

Source: Testimony of Frank T. Princiotta, Dir., Air and Energy Engineering Research Lab at R.T.P. North Carolina, U.S. E.P.A., before the House Subcommittee on Synthetic and Fossil Fuels, February 27 and March 28, 1985.

7. Question

Are the technologies being developed by the DOE clean coal technology program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?

7. Answer

Since the regulated electric utility industry is subject to the scrutiny of rate-setting commissions, it is unlikely that companies will choose to reduce the level of air emissions absent regulations. Utilities are increasingly being challenged for expenses consider "imprudent" by the commissions.

If a regulated electric utility cannot be given a guarantee its investments will be returned, it has no incentive to voluntarily retrofit existing euipment with pollution control equipment. However, a Commission would be under pressure to grant a rate of return sufficient to recover costs of new equipment mandated by federal or State regulatory authorities.

One could argue that corporate responsibility should dictate voluntary environmental improvements within the electric utility industry but that is impractical, in light of the basic motivations of stockholders.

7(b). Question

A more direct question is:

'how can new regulatory requirements assure deployment of CCTR technologies?'

7. Answer

A practical answer can be found by looking closely at the boiler life extension trend and creating a regulatory climate to encourage that practice while reducing air pollution emissions from those boilers.

Many of those aging boilers are the very targets for emission reductions of acid rain legislation. If all boilers had to meet a tougher pollution emission level after maturing beyond their book life, they could remain on line indefinitely and limit their contribution to the acid rain problem. The technology options they need to reduce emissions by amounts less than would be required by N.S.P.S. should be demonstrated in the CCTR. Direct lime injection, advanced coal washing, atmospheric fluidized-bed combustion and the combined use of natural gas and coal are examples of old boiler retrofit technologies those plant operators will need.

8. Question

Mr. Donald Bauer, on behalf of DOE, stated that performance testing generally will not be completed until the early to mid-1990's. He concluded with the observation that,

"if the timetable established in HR 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options." Do you agree?

8. Answer

The two issues of acid rain control legislation and the timetable of the CCTR are separate but related. The problems caused by acid rain must be resolved quickly through a national program to reduce SO2 and NOx emissions from stationary and mobile sources. The successful demonstration of clean coal technologies will aid that effort but cannot provide all of the answers. State-of-the-art emission reduction equipment, such as fluegas desulfurization "scrubbers", will have to provide the largest increment of emission reductions.

Consider the following data pertaining to the emission levels and generating capacity of the nation's 200 largest SO2 sources in 1980:

1980 SO2 EMISSION RANK	TOTAL MW	TOTAL TONS OF SO2 EMITTED	TONS OF SO2 PER INSTALLED MEGAWATT
1-200	228,138	14,984,800	65.68
1-50	87,331	8,430,000	96.52
1-100	147,628	11,779,600	79.76
101-200	80,460	3,205,200	39.84

It is evident, on a cost-effectiveness basis, the nation's largest non-NSPS coal-burning powerplants are the obvious candidates for retrofit of pollution control equipment; primarily flugas desulfurization equipment. To consider those plants as more likely candidates for clean coal technologies ignores the limits of economics and emission reduction potential those control processes offer.

The largest SO2 source in the nation, the James Gavin powerplant in Southern Ohio, emits about 370,000 tons annually. Its twin 1300 MW boilers went on line in the early 1970's. That powerplant is not a candidate for a fluidized-bed retrofit, an IGCC retrofit or direct lime injection because its mammoth boilers and long remaining service life make it improbable, if not impossible, that anything will be done to the boiler itself to reduce emissions.

The most sensible option for the reduction of SO2 emissions from the Gavin plant and others of its size and vintage is the federally cost-shared installation of a scrubber with a 90-95% SO2 removal efficiency. That equipment is available off the shelf. The CCTR will provide options for those smaller and older units that are more likely candidates for simpler and less efficient removal technologies than scrubbers.

The envrionmental problems caused by acidic deposition in sensitive ecosystems are time-related. As the natural buffering capacity of soils are weakened and eliminated by high ion exchange, these ecosystems face continuous damage.

Liming of lakes and other acid-neutralizing methods are not practical, very expensive and address only short-term reclamation. Thus, only a reduction of deposition levels below that which is considered a "threshold for safety" can resolve the problem of acid rain. The longer the U.S. delays the implementation of an emission reduction program, the more serious will be the damage to North America's environment.

9. Question

One of the premises behind the Clean Air Act was that industry would gradually retire old facilities and replace them with new installations subject to "new source performance standards". Consequently, there would be a gradual improvement in air quality.

In your judgement has this occurred?

In asking this question, it is observed that EPA Administrator Thomas, commenting on plant life extension trends, stated that,

> "this postpones the rate at which new sources will replace existing sources, making New Source Performance Standards a less effective way of reducing overall emissions in the near or middle term".

9. Answer

The legislative history of the 1977 Act is explicit regarding Congressional intent to limit the growth of air pollution from new stationary sources. Amendments to Section 111 (New Source Performance Standards (NSPS)) require new plants to continuously use the best adequately demonstrated air pollution control technology; not merely rely on untreated low sulfur fuels to comply with those performance standards. It also made clear that intermittent or alternative air pollution control measures are no longer a permissible means of compliance.

The 95th Congress was less affirmative when it considered emission regulations for "existing" (non-NSPS) stationary sources. They remain subject to SO2 emission levels specified in each State Implementation Plan (SIP). NSPS sources are limited to no more than 1.2 pounds of SO2 per million Btu's of heat generated (1.2 lb SO2/MMBtu) and a sliding scale of reductions. Plants burning high sulfur-content coal must remove 90% of the SO2 and those using low sulfur coal must achieve a 70% reduction. In Missouri, for example, an NSPS facility is limited to no more than 1.2 pounds of SO2/MMBtu while a nearby existing plant may emit more than 4 pounds. The 1977 law defined a new source as:

> "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source".

Applying these performance standards only to new sources appears to have been a recognition of the difficulty and expense of retrofitting existing sources with continuously operating best available control technology. The House Report accompanying the 1977 Act concluded, "It was only right that the cost of applying best practicable control techonolgy be considered by the owner of a large new source of pollution as a normal and proper expense of doing business." The electric utility industry, in the 1975 Clean Air Act hearings testified that:

> "Proven FGD systems are justified for new plants utilizing higher sulfur fuels where sizeable emission reductions are needed to meet new source performance standards....[I]t is imprudent to backfit FGD into existing plants, especially older units facing retirement within 10-15 years."

The Congress also considered the economic benefits of applying best technology requirements only for larger new sources. " Older plants with relatively short-remaining useful lives might have chosen to cease operation if the only means of emission limitation available to meet emission limits were pollution control technology. This is particularly true with respect to plants which are marginal or near marginal economically. By freeing naturally low sulfur coal or oil for use in these plants, higher capital costs could be avoided here and employment opportunities preserved." Can this deference to technical and economic considerations about retroffiting existing sources be interpreted as a willingness of the Congress to forfeit reductions of SO2 emissions from those sources for an indeterminate time?

The 95th Congress understood the temporary tradeoff it was making with the electric utility industry when it passed up the opportunity to set a much tighter cap on SO2 emissions for existing plants. When the U.S. Congress enacted the 1977 federal Clean Air Act, it included amendments intended to promote continuous improvements in air quality. Among the most effective, the New Source Performance Standards (NSPS) imposed tougher sulfur dioxide (SO2) emission limits on boilers constructed after the 1977 regulations went into effect. When they approved that law, the legislators anticipated a routine replacement of old and less stringently regulated equipment with new, pollution control-equipped boilers.

That goal is being frustrated, however, by electric utility managers choosing to continue operating old generating equipment and forgoing new construction. In light of the flattened electricity demand curve in the Midwest, the high capital cost of new power-generating equipment, and regulatory uncertainties, boiler life extension is becoming the preferred option for electric utility companies. It also represents a reversal of the nation's air quality improvement strategy since those older boilers will contine to emit levels of SO2 above that which technology can remove.

Now, the international concern about U.S. - Canadian SO2 and NOx emissions damaging sensitive aquatic and terrestrial ecosystems has reordered the nation's needs. It is time for the Congress and E.P.A. to revisit the issue of non-NSPS boilers remaining on line longer than was intended.

The utility industry must also defend its reversal of the traditional policy of retiring old equipment. It certainly made clear to the 94th and 95th Congresses that retirement was a justification for not imposing new source-equivalent standards on exisitng plants. If an honest bargain was stuck then, both parties should abide by its terms today. And, if the Congress finds that it must require NSPS standards on those units to solve the acid rain problem, the federal government should front a great deal of the capital needed for the flugas desulfurization equipment.

10(a). Question

In your opinion, what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the various legislative proposals before the Congress?

10(b). Answer

The electric generation systems serving market areas which continue to suffer the effects of the recent economic recession have considerable excess generating capacity. When faced with mandatory emission reduction orders, it can be presumed their reaction will be to mothball as much equipment as its service realiability requirements will allow. That is the obvious least cost compliance method. And, it provides the opportunity to add that generating capacity when demand grows again at comparably low costs (emission control retrofit costs versus new construction). However, that option will not satisfy the reduction requirements likely to be imposed upon companies in Ohio, Indiana, West Virginia and Pennsylvania.

The next steps would involve the utilization of the least expensive technologies and methods of compliance for on-line equipment. These options include coal washing and blending, switching to lower sulfur fuels, combustion of coal and natural gas in the boiler unit, and least emissions dispatching schedules. Each option has its built-in costs to the company such as abandonment of some mine-mouth coal reserves having high sulfur content, increased fuel transportation costs or operating some equipment longer and harder than design specifications had intended.

10(b). Question

Is the electric utility industry likely to rely on extension of the life of exisitng facilities rather than their retirement and replacement with new facilities?

10 (b) Answer

As a consequence of several factors - including the continued effects of the economic recession in the Midwest, foreign trade competition and the success of energy conservation programs - electric energy demand has begun to level off nationally. From its traditional 5-7% annual growth rate, demand has fallen sharply within some markets while fixed costs, fuel costs and the costs of regulatory compliance have increased. The result, for some electric utility companies, particularly those in the Midwest, is a reevaluation of current and projected construction schedules and delay or postponement of new construction.

According to Jack Ferguson, Executive Vice President of VEPCO, the industry is currently in a hiatus period in which very little new generating capacity is being built. In testimony before the U.S. House Committee on Energy and Commerce, in March of 1985, he stated: "While many utilities are completing their construction projects, others are cancelling units on order and virtually no new orders are being placed. The pipeline of new generating capacity is emptying out."

Fred D. Williams, Georgia Power Co. Vice President of bulk power markets says his company will focus its design and construction efforts on extending the operating life of its coal-fired plants and getting a larger share of its power from intermediate and peaking technologies. It does not plan to put a new coal plant on line until 2007. In a January, 1985 newspaper interview he said: "We feel confident that, with the proper modifications, we can extend the operation of units well beyond their previous retirement cates. Last year we planned to build 11 new 789 MW coal units to replace this retired capacity. This year's plan shows that this same amount of coal-fired capacity will be retained on the system through the continued operation of these existing units, but at a fraction of the cost of building the new units over this same period."

The decision to upgrade and not replace old electric utility boilers may provide consumer savings and, from that aspect, we support this trend within the industry. According to Duke Power s, William Parker, Jr., "Assuming that costs for upgrading for extended service will range from normal maintenance to $100/kW, there is a tremendous economic incentive to continue the operation of existing plants as an alternative to new plant additions costing an average of $1100/kW or 20 times the option of life extension". These savings appear to be large enough to justify emission reduction requirements at the same time the capital is committed to boiler life extension.

Furthermore, clean air advocates should not expect boiler life extension projects to be compelled to install NSPS-capable retrofit equipment as a compliance requirement. Emissions reductions should be required -- and they can be achieved -- without mandating the use of pollution control equipment capable of 90-95% removal efficiency.. The economies of boiler life extension will be protected when emission reduction technology options are allowed.

Allowing the use of technologies not as effective as fluegas desulfurization or comparable emission control equipment is not a retreat from the 1977 Clean Air Act's goal of continuous national power plant emission reductions. However, allowing unregulated boiler life extension is more than a retreat; it is a direct threat to that goal. In fact, Schwengels, et.al., report the conclusions of sensitivity analyses show the change in assumed retirement age of boilers from 45 to 60 years resulting in a total national SO2 emissions increase of 4-6 million tons by 2010. That is clearly unacceptable.

11. Question

In your judgement, to what extent is industry's decision to extend the life of an existing facility influenced by regulatory policies?

11. Answer

Though the Environmental Policy Institute has not evaluated the effects of regulatory policies upon the utility industry's decisions to replace or upgrade generating equipment, it appears that costs and boiler heat rate efficiencies are stronger determinants for boiler life extension than are regulations.

Comparisons between replacement costs and boiler upgrading costs require extensive site specific analysis and economic evaluation of the options. If a generalization of the capital savings is not in order, it is worth considering the views of three electrical engineers addressing the 1984 American Power Conference, in Chicago, as they estimated their company's savings.

Robert Carelock, staff engineer of Potomac Electric Power Co. described the decision to refurbish the 400 MW Potomac River station and extend the service of this retirement candidate to the year 2012 at a cost of $160/kW. Cincinnati Gas and Electric's Barry Pulskamp explained his company's willingness to spend an average of about $200/kW vs. $1000-$2000/kW for new capacity. Leonard McRee, of Duke Power, considered life extension "very economical" when comparing the $2000-$3000 for new capacity with $200-$300 for extending life of capacity.

Technological advancements in boiler design have provided great economies of scale since the 1950's. With the current high costs of material, labor and capital, however, the economies of large boilers have declined; and, there has been little improvement in unit heat rates for fossil power plants over the past 20 to 30 years. These are both good reasons for choosing the life extension option over new construction but they cannot be used as a subterfuge to escape the NSPS requirements imposed on new capacity.

11(b). Question

For example, as I understand EPA regulations, at a certain point the costs of retrofitting an existing facility become great enough that it runs the risk of being classified as a new one subject to New Source Performance Standards.

Would you comment?

11(b). Answer

In the 1977 Clean Air Act, the term "modification" is used in the definition of a "new source" and is, therefore, subject to N.S.P.S. requirements. "Modification" is defined in the regulations as:

> "any physical change in, or change in the method of operation of, an existing facility which increases the amount of any pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted." (emphasis added)

In the regulations, there is an important distinction between "modification" and "reconstruction"; the latter being defined as:

> "the replacement of components of an existing facility to such extent that:
>
> (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and
>
> (2) it is technologically and economically feasible to meet the applicable standards set forth in this part."

Note: It is important to point out that the "50% of the fixed capital costs" is simply a regulation and not a provision of law. Given the disproportionate costs of boiler life extension and replacement, the 50% ceiling is meaningless and should be revised downward. It can be reduced to a more appropriate level merely by E.P.A.'s initiating a rule-making procedure.

For power plants which substantially retain their character as existing facilities, application of best adequately demonstrated control technology is considered appropriate when any physical or operational change is made which causes an increase in emissions to the atmosphere. This is consistent with the principles of the Act's Prevention of Significant Deterioration provision. Thus, the regulations contain criteria for "reconstruction" (capital costs) that are independent from the criteria for "modification" (emissions increase).

The "fixed capital cost" includes such things as the cost of engineering, purchase and installation of major process equipment, contractor's fees, instrumentation, auxiliary facilities, buildings and structures. Costs associated with the purchase and installation of air pollution control equipment (e.g., baghouses, electrostatic precipitators, scrubbers, etc.) are not considered in estimating the fixed capital cost of a comparable entirely new facility.

When the EPA Administrator is asked to make a determination whether proposed replacement of components constitutes "reconstruction" he must consider:

(a) whether the estimated life of the facility after the replacement is significantly less than the estimated life of a new facility;

(b) the extent to which the components being replaced cause or contribute to the emissions from the facility;

(c) any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

From this discussion of the distinctions between modification and reconstruction, there are obvious implications for Georgia Power Co. and all boiler operators considering life extension projects. Either the increased amount of emissions (measured in kg/hr) or capital expenditures exceeding 50% of replacement costs can trigger the imposition of the percentage reduction requirements in the NSPS regulation. If that is the regulatory affect of a utility's boiler life extension proposal, it is likely the project will not be completed. However, a utility can appeal to E.P.A. for a waiver of NSPS requirements by proving there are economic and technical limitations on complying with those standards.

12. Question

The Clean Air Act provides for an extension of compliance dates for facilities that propose to use new or innovative technologies to comply with emission standards. In your judgement, has this authority been effectively implemented by the EPA?

12. Answer

The use of Section 111(j) of the Clean Air Act (providing commercial demonstration waivers) may be essential to the success of the Clean Coal Technology Reserve; particularly when emission reduction processes are being tested on existing sources. However, its application within the E.P.A. has not been entirely satisfactory from the viewpoint of the Agency or the applicants.

There appears to be a need to specify more clearly the risks boiler operators face when they petition the Agency for the waiver. They must know what the regulatory consequences will be if the technology does not work; requires additional time and refinement; or, can not achieve the anticipated reduction level or reliability.

The Environmental Policy Institute advocates a closer relationship of the CCTR with Section 111(j). The Department of Energy and the E.P.A. should coordinate implementation of the waiver and the demonstration timetable to assure participants will have adequate time and flexibility to complete the construction and testing activities. This coupled administrative approach need not compromise the enforcement of the federal Clean Air Act and it can facilitate the completion of the clean coal demonstration projects.

13(a). Question

What is the national average cost of FGD retrofit per kilowatt?

13(a). Answer

To discuss the national average cost of FGD retrofit per kilowatt, each FGD process must be identified and the range of installed and opertaing costs compared. The following table provides the low and high costs for retrofitted equipment operating in 1984.

FGD PROCESS	NEW/RETRO	INSTALLED COSTS ($'S/kw)		O & M COSTS (mills/kwhr)	
		HIGH	LOW	HIGH	LOW
LIMESTONE	RETRO	158.1	81.3	7.28	4.79
	NEW	162.1	38.3	9.74	3.18
LIME/ALKALINE/ FLYASH	RETRO	N.A.	N.A.	N.A.	N.A.
	NEW	184.4	52.5	14.09	2.99
LIME SPRAY DRYING	RETRO	120.0	N.A.	N.A.	N.A.
	NEW	N.A.	N.A.	N.A.	N.A.
LIME	RETRO	210.0	102.4	17.65	5.30
	NEW	181.1	66.0	10.27	4.03
DUAL ALKALI	RETRO	87.8	N.A.	7.23	N.A.
	NEW	263.9	88.4	13.94	4.98
WELLMAN-LORD	RETRO	282.2	277.9	16.89	16.70
	NEW	N.A.	N.A.	N.A.	N.A.
SODIUM CARB	RETRO	87.1	N.A.	5.78	N.A.
	NEW	118.4	N.A.	6.81	N.A.
MAG OXIDE	RETRO	N.A.	N.A.	N.A.	N.A.
	NEW	N.A.	N.A.	N.A.	N.A.

Source: COST AND QUALITY OF FUELS FOR ELECTRIC UTILITY PLANTS, 1984. U.S. Department of Energy, Energy Information Administration, July, 1985; DOE/EIA-0191 (84).

From the above data, it is difficult to provide a national average cost of FGD retrofit or new construction since the various processes vary so widely in installed and operating costs.

13(b). Question

And, what would be the cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements?

13(b). Answer

In 1984, the U.S. E.P.A. estimated the cost of installation and operation of FGD systems on the 50 largest SO2-emitting powerplants (listed in HR 3400). Using 1980 dollars, the

PEDCO report estimated a total capital cost of $10.6 billion; annual costs of $3.55 billion and annual O&M costs of $1.7 billion. The total SO2 emissions from those units exceeded 8.4 million tons in 1980. Assuming a 90% removal efficiency for those FGD units would provide about 7.5 million tons of SO2 removed. If a 10 million ton SO2 reduction program were mandated, $12.5 billion would be a very rough estimate of the total capital cost of retrofitting FGD systems on all targetted equipment sufficient to meet the emission reduction goal.

14. Question

In your judgement, is the mandate for the Clean Coal Technology program broader in scope than the demonstration program set forth in the Special Envoys Report?

14. Answer

The mandate of the CCTR is, by necessity, broader in scope than the demonstration program the Special Envoys advocated. Since the Report focussed upon U.S. contributions to Canada's acid rain problem, it was not concerned specifically with acid deposition sources and receptors elsewhere in the U.S. Thus, SO2 emission control research for Western State coal-burning facilities and those designed to use Western subbituminous and lignite coals were not considered priorities in the Envoys' Report.

Viewed in another way, the CCTR is being implemented by the DOE and its jurisdiction includes the entire U.S. and all industrial uses of coal. An applicant in the Southwest or Pacific Northwest has as much right to participate as do those in New England and the Midwest. The former have little relationship to the acid rain problems of the Northeast, while the latter are intrinsically involved.

The Special Envoys' recommendations had to focus upon the transboundary transport of pollution from those sources which are impacting the sensitive areas of the Northeast and Canada. That requires a more limited geographic target area of sources with specific sites and boilers. The U.S. E.P.A. is the only federal agency equipped to model air quality, regulate emissions levels, mandate the use of best available control technologies and determine which emission reduction plans are acceptable under existing State and federal laws. Therefore, the demonstration program recommended by the Special Envoys is entirely different from the CCTR and neither program should be joined except for the fact they encourage the same end; the demonstration of pollution control retrofit equipment for coal-burning facilities.

The prevention of air pollution damage to sensitive ecosystems is dependent upon reducing acid deposition levels below identified thresholds. Acid rain control cannot be measured in terms of dollars spent. It must be discussed in terms of deposition rates or their reduction to safe levels. That a $5 billion outlay of federal or private funds would reduce SO2 emission levels is not disputed. What is being questioned is the degree of protection sensitive areas will gain if the Envoy's recommendations are followed in lieu of federally mandated emission reduction orders.

15. Question

In the longer term, is the trend toward upgrading and not replacing oil boilers in the national interest from the standpoint of achievement of either energy or environmental policies?

15. Answer

If boiler life extension represents economic savings to electric utility customers, that trend within the industry should be encouraged. However, the significant savings offered by continued use of equipment provides capital for simultaneous emission reductions from those plants operating beyond their normal book life. The goal of consumer and environmental public interests should be the establishment of a regulatory climate which allows the achievement of both; consumer savings and environmental protection.

Electric utility managers can manipulate the boiler life extension option in lieu of new construction by incorporating market-oriented incentives or imposing load management practices. If the peak demand of a service area can be held constant or diminished while the load is balanced more evenly, it may be possible for some utility companies to continue avoiding new construction for another decade or longer. The limiting factor of boiler operating safety and a return to demand increases witnessed in the 1970's then become the determinates for replacement and new construction.

QUESTIONS SUBMITTED TO

KURT E. YEAGER

HEARING ON
CLEAN COAL TECHNOLOGY AND ACID RAIN CONTROL

1. EPA Administrator Thomas, on behalf of the Administration, stated that,

   > "we do not yet believe that the current state of knowledge can sustain any judgement with respect to the level of emission reductions needed to prevent or eliminate damage."

   Do you agree with this statement?

2. EPA Administrator Thomas added,

   > "this is true even for the area of greatest scientific understanding, sulfur emission and surface water acidification. In the area of the impact of acid deposition on forests, we have yet to determine if a cause and effect relationship exists."

   Do you agree with this assessment of current knowledge?

3. On the basis of current knowledge of the causes of acid rain, in your judgement, can we formulate a control strategy that will assure achievement of the intended mitigation of acid rain once the prescribed control investments have been made? In other words, can we determine what pollutants need to be controlled, the size reductions that are called for, where the reductions should take place, and over what time frame they should be implemented?

4. There has been considerable discussion of the need to place emphasis on the development of clean coal technologies with retrofit application. For example, the Special Envoys Report emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

   EPA Administrator Thomas emphasized in his testimony that "the most important application category for the focus of clean coal technology development would be the coal-fired retrofit application". Do you agree?

   a. In your judgement, does the DOE Clean Coal Technology program adequately reflect this need? Or does the program place too much priority on technologies applicable to new construction?

   b. Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control? Should they be?

5. Under what circumstances will life-extension result in reduced atmospheric emissions?

6. What is the potential that the types of clean coal technologies under discussion will be able to meet New Source Performance Standards without the use of scrubbers?

7. Are the technologies being developed by the DOE clean coal technology program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?

8. Mr. Donald Bauer, on behalf of DOE, stated that performance testing of clean coal technologies under consideration by DOE generally will not be completed until the early to mid-1990s. He concluded with the observation that "if the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options". Do you agree?

9. One of the premises behind the Clean Air Act was that industry would gradually retire old facilities and replace them with new installations subject to "new source performance standards". Consequently, there would be a gradual improvement in air quality. In your judgements has this occurred?

   In asking this question it is observed that EPA Administrator Thomas, commenting on plant life extension trends, stated that, "this postpones the rate at which new sources will replace existing sources, making New Source Performance Standards a less effective way of reducing overall emissions in the near or middle term".

10. In your opinions, what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the various legislative proposals before the Congress? For example, is the electric utility industry likely to rely on extension of the life of existing facilities rather than their retirement and replacement with new facilities?

11. In your judgement, to what extent is industry's decision to extend the life of an existing facility influenced by regulatory policies? For example, as I understand EPA regulations, at a certain point the costs of retrofitting an existing facility become great enough that it runs the risk of being classified as a new one subject to New Source Performance Standards. Would you comment.

12. The Clean Air Act provides for an extension of compliance dates for facilities that propose to utilize new or innovative technologies to comply with emissions standards. In your judgement, has this authority been effectively implemented by the EPA?

13. What is the national average cost of FGD retrofit per kilowatt? And, what would be the cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements? What would be the differential cost between implementation of the above options?

14. What, in your judgement, are the estimated costs of implementing proposed acid rain legislation? Would you indicate the sources of such cost estimates and whether you agree, or disagree, with such analysis?

15. What in your judgement, are the comparative roles of different source contributors of air pollution as contributing factors in acid precipatation? Would you indicate the sources of such information and whether you agree, or disagree, with such analysis?

Answers to Questions Submitted to Kurt E. Yeager

Bearing on Clean Coal Technology and Acid Rain Control

1. We agree. First of all, we are not able to quantify the source/receptor relation, i.e., we cannot say how a change in emissions (from either a local or distant source) will change what, or how much, is deposited; hence even if we know what a depositional level should be, we cannot say how that level could be achieved barring total elimination of all emissions. Secondly, we are totally devoid of dose-response data on deposition as related to effects. In other words, we cannot quantify a cause/effect relation.

2. We agree. A number of theories exist to explain forest decline--theories that involve man's activities and those that involve natural phenomena. No consensus exists on which theory(s) is preferred. Furthermore, the extent of forest decline has not even been assessed.

3. In our judgment, no. The responses to questions 1 and 2 underscore the uncertainties that exist in the current knowledge of the causes and effects of acid rain. Until these uncertainties are resolved, any control strategy remains speculative at best in terms of its impact on the phenomena known as "acid rain." Congress created NAPAP to coordinate and monitor a comprehensive national research effort to resolve these uncertainties and determine whether additional controls are necessary. This is a rational approach that should be encouraged to complete its planned scientific and policy assessments.

   Further, we believe that the growing understanding of the complex interaction among pollutants indicates that the nation should be concentrating on developing an effective, sustained strategy to continue the substantial progress which has been made in the last decade in emission control. Especially important is vigorous application of new, clean coal utilization technologies that combine emission control with the combustion or conversion process. The principle that guides the development of these technologies is that real and sustained environmental improvement is only possible when both emission and cost reduction are achieved concurrently - not pitted against each other. Unfortunately, the various legislative proposals currently under consideration tend to ignore this reality. The inflexible emphasis on "band-aid" retrofit controls, which compromise both productivity and sustained environmental protection, tends to discourage innovative clean coal technology and limit technical freedom of choice.

4. No, I do not entirely agree. Retrofit applications are inherently compromises that reduce both environmental control and cost effectiveness. In my judgment, their place

in clean coal technology development is to provide an insurance policy in the event that scientific evidence ultimately indicates that additional, short-term controls are necessary. In this case, their primary objective is to satisfy, at reduced cost, the void between present physical coal cleaning and flue gas scrubbing. The insurance role is further underscored by the fact that SO_2 emissions have been reduced substantially over the past decade under the existing Clean Air Act, and all evidence indicates that this trend will continue without resort to additional control requirements.

I believe greater emissions control progress can be achieved and sustained by placing first priority on the development and accelerated application of improved, clean coal utilization alternatives such as fluidized-bed combustion and coal gasification, primarily for new plant and repowering applications. Such alternatives combine high levels of emission and effluent control with reduced cost. While also applicable in retrofit situations, their benefits can best be achieved through new plant application or repowering existing plants. In short, this emphasis improves all aspects of air, water, and solid waste control, plus productivity and cost, rather than pitting one against the other, which is inevitably the case in retrofit applications.

a. I believe the Clean Coal Technology program as defined by Congress originally encouraged the appropriate balance between new and retrofit applications. Its primary objective was to enhance and expand the clean use of coal as a strategically important national energy resource.

Unfortunately, the DOE interpretation as reflected in the February 17, 1986 Program Opportunity Notice (PON) tended to particularly discourage retrofit applications. As indicated above, retrofit applications do not have the same cost and productivity advantages to the user as new plant or repowering technology. Thus the cost-sharing confusion and excessively detailed information requirements of the PON took a proportionately greater toll on the quantity and quality of responses in the retrofit categories.

b. Yes, most clean coal technologies potentially funded by DOE are likely to be applicable to SO_2 and/or NO_x control and thus will reduce those precursors associated with the acid rain phenomena. I do not, however, believe that this should be the only criterium for judging "clean" coal technology. While acid rain commands center stage today, in the longer term other issues, such as solid waste disposal and reuse, may become increasingly important factors in coal use.

Thus, technology development should not focus too narrowly on one emission issue with the result that other issues are worsened. This again argues against a focus on retrofit air quality controls whose compromise includes increased solid waste and water quality impacts.

5. The recent EPRI sensitivity analysis of electric utility emissions indicates that the current downward trend in SO_2 emissions will be sustained for the foreseeable future even with planned life extension. As described in Attachment A to my June 10 testimony, the analysis indicates that up to 76% of existing coal-fired units without scrubbers could continue their operating life to 60 years without forcing SO_2 emissions to rise on a national basis. It is interesting to note that over the remainder of the century this capability is only very marginally affected by energy demand growth rates over a range of 2.3 to 3.3%/yr. Over the next decade, for example, only 20 GW of coal-fired generating capacity may be operated beyond 40 years of service life while 113 GW of new generating capacity, meeting or exceeding NSPS, is scheduled to come into service. Only in the Southwest and Far West would life extension be restricted to substantially lower levels to avoid a rise in SO_2 emissions. This results from the very low emission levels now existing in those regions.

   This analysis considers the interaction of regional growth rates in electricity demand, reserve margins, retirement and life extension, fuel sulfur content, and existing national and local emission regulations. Major assumptions used in this analysis on a national basis are:

   - 2.3% average electric energy demand growth (1985 NERC projections for both peak capacity--GW and energy demand--GWh). Alternatively, a 3.3% demand growth was also considered.
   - 20% planning reserve margin
   - No nuclear additions after 1994
   - No further reduction in current fuel sulfur content
   - Regional NERC projections and individual power plant data for capacity mix, fuel type, plant heat rates, capacity factors, fuel heat content and composition, and demand growth.
   - Plant service life of both 40 years and 60 years.
   - 1979 New Source Performance Standards are maintained.

- Individual state emissions reduction requirements are implemented as mandated.

6. Those clean coal technologies that are intended for new plant or repowering applications will meet existing New Source Performance Standards (NSPS). These include primarily fluidized bed combustion, coal gasification and liquefaction, and fuel cells. In the case of retrofittable technology, only fluidized bed combustion and improved flue gas scrubbing technology are designed to generally meet NSPS for SO_2. In addition, fluidized bed combustion and new low-NO_x burner technology can meet NSPS for NO_x in retrofit applications. Other retrofittable clean coal technologies focus primarily on reducing the cost and complexity of control and do not achieve NSPS levels of emission reduction. These include coal cleaning, furnace sorbent injection (LIMB), and partial scrubbing. It should be noted, however, that the cost effectiveness of these simplified options in terms of \$/ton of SO_2 removed is typically greater than that of wet scrubbing.

7. In my judgment, the technologies being developed under the DOE clean coal technology program for new plant applications will be used without new regulatory requirements because of their inherent cost advantages as well as emission control capability. We see this today most dramatically for atmospheric fluidized bed combustion (AFBC) where commercial utility and cogeneration commitments are accelerating rapidly. This conclusion is supported by the following economic analysis done by Wisconsin Electric Power Company (WEPCO). This led to their commitment to convert Units 1-4 (410 MW) of their Oak Creek Power plant to AFBC.

Discounted Accumulated Revenue Requirements
Differences over 30 Year Period
(Million of 1985 $)

A.	AFBC Conversion	Base
B.	Retire and Replace with New Plant	+164
C.	Restore, Add FGD	+330
D.	Restore, No FGD	+150

Unfortunately, the new legislative proposals for acid rain are likely to delay the use of these new technologies by forcing the industry to divert needed capital into retrofitting wet flue gas scrubbers to newer existing plants, which are too large to be confidently retrofitted by the regulatory deadline with first generation clean coal technology such as AFBC. Conventional wet scrubbing remains the only retrofittable control option available for most existing plants to meet the proposed emission reduction requirements in the time frame required.

In the case of retrofittable technologies now under development, improved though still very expensive, flue gas scrubber technology is likely to be used under existing NSPS for new, conventional, pulverized-coal plants now in planning and construction. The other retrofittable control technologies, which do not meet NSPS, may be used to meet State Implementation Plans (SIPs) or, as in the case of coal cleaning, to reduce the quantity and cost of SO_2 to be scrubbed. Again, any new regulatory requirements, when justified, should emphasize flexibility and cost effectiveness if these simplified retrofittable options are to be encouraged. Unfortunately, the acid rain legislation now being proposed does just the opposite.

8. Yes, the timetable for HR 4567 conflicts with the realistic demonstration and commercial deployment schedule for new clean coal technologies. Although this proposed legislation is phased, even the initial requirements will restrict the high sulfur coal burning states in the midwest and midsouth to conventional flue gas scrubbing. This is the only commercially proven method available for control of SO_2 emissions to the level required from larger (greater than 300 MW), pre-NSPS, high sulfur coal-fired generating units by 1993.

9. Yes, to date the replacement of old facilities with new plants meeting NSPS has occurred with the result that air quality has steadily improved. Over the past decade, for example, utility SO_2 emissions have dropped about 20% while coal use has increased 70%. As we look to the future we see this downward trend in SO_2 emissions continuing even if life extension of existing coal-fired plants is implemented as discussed in the response to Question 5. Over the next decade, for example, the industry will add 113 GW of new clean generating capacity - primarily coal and nuclear, all meeting or exceeding NSPS. By comparison, only about 20 GW of coal-fired capacity will reach 40 years of age. It is more likely that a similar amount of oil and gas capacity will extend life because of the reduced cost of these fuels in at least the short term. Thus, contrary to the observation of the EPA Administrator, I believe very little postponment of new sources meeting NSPS is likely because of life extension and that a large fraction of what ever life extension occurs, over the next decade at least, will be in generating units using oil and gas.

10. The industry response is, of course, likely to vary depending on the requirements of the legislation and the local conditions affecting each corporation. Examining HR 4567, the primary technology determining requirements are

    a. Statewide average utility SO_2 emission rate of 2.0 lb/MBtu by 1993.

b. Statewide average utility SO_2 emission rate of 1.2 lb/MBtu by 1996.
c. Statewide average utility NO_x emission rate of 0.6 lb/MBtu by 1996.

Under (a), the states primarily affected would be OH, IN, PA, MO, IL, KY, TN, WVA, AL, GA and WI. These 11 states must satisfy about 90% of the national SO_2 reduction required under this proposed legislation. In these states SO_2 emission reductions of 25 to 50% will be required to satisfy (a). Although this level of SO_2 reduction is generally consistant with the control capability of the developmental retrofit clean coal technologies, the 1993 deadline for achieving this level of reduction will not be consistent with the time frame necessary for demonstration and subsequent commercial deployment of these options on the massive scale necessary. As a result, only a few of the affected utilities may be able to use coal switching, more intense coal cleaning, or AFBC conversion. The majority will be limited to flue gas scrubbing.

The decision to use flue gas scrubbing will be further encouraged by the requirements of (b) which must be met by 1996. In this case the level of SO_2 reduction in the primary affected states will typically increase to 50-75% and the capacity affected will increase to 150 GW. This control level will exceed the SO_2 reduction capability of most of the lower cost, simplified retrofittable control options now entering demonstration, thus rendering them generally ineffective. In the remaining states, where about 10% of the SO_2 reduction requirement will occur, the flexibility to use these emerging technologies will be greater. Unfortunately, the states with the greatest control requirements will have the least flexibility in SO_2 control method.

Under (c) the retrofittable low NO_x burner and combustion modification technology now entering demonstration, if successful, should be capable of supporting the level of control and schedule defined by the proposed legislation. It should be noted that this NO_x control requirement will also have a broader impact in terms of states affected than the SO_2 control requirements.

The proposed Senate legislation (S 2203) has even more restrictive requirements which further limit freedom of control choice and expand the impact to essentially all coal-fired plants. The requirements most affecting technology choice are:

a) Units achieving an SO_2 emission rate of 0.7 lb/MBtu or less have unlimited operating life.

b) Units with an SO_2 emission rate between 0.7 and 1.5 lb/MBtu would be restricted to 10,000 hrs of additional operation after 1991.

c) Units with an SO_2 emission rate greater than 1.5 lb/MBtu would be restricted to 3,000 hrs of additional operation after 1991.

d) Plants reaching 35 years of age by 1991 would have to meet current NSPS.

e) By 1995 all plants must apply best achievable NO_x reduction based on OECD demonstrated technology.

Since 10,000 hours is only about two years of operation, based on the utility industry's average load factor for coal-fired power plants, requirements (a) (b) and (c) will force stringent control, far exceeding current NSPS, on essentially all the 180 GW of pre-NSPS coal-fired power plants in the U.S. as well as a substantial number of post-NSPS and oil fired plants.

In the high sulfur coal burning power plants of the midwest and midsouth, the level of control required will typically be 70% to 90%. Among the various retrofittable, clean coal technologies under development, only AFBC may be applicable and then only to the smaller (less than 300 MW), older generating units. At most this will be 15% of the total generating capacity requiring control. The remainder will be limited to flue gas scrubbing.

In low sulfur coal-and many oil-burning plants in the remainder of the country, the level of control will typically be 25% to 50%. While this is more consistent with the control capability of the developmental retrofit technologies, the deadline of 1991 is not consistent with the required broad commercial application, particularly on the newer, larger plants. It is also important to note that even the lowest sulfur content coal available cannot satisfy the 0.7 lb/MBtu SO_2 emission limit. Thus, coal switching is rendered impractical unless substantial additional emission control technology is also added.

The very restrictive requirements of S 2203 are likely to force, on economic grounds, the premature retirement of valuable generating capacity, particularly in the high sulfur coal using states. This will exacerbate the electric generation supply shortage expected in the later 1990s. The likely result for consumers and industry will be a decrease in the quantity and reliability of electrical service. This would be coupled with a rapid rise in electricity cost, likely forcing industry to relocate away from the affected regions to remain competitive.

Requirement (d) will also have a very restrictive effect on the use of low NO_x combustion technology now entering demonstration. Demonstrated technology within the member countries of the Organization for Economic Cooperation and Development (OECD) by 1995 will include complex and expensive, catalytic, post combustion NO_x reduction technology. Although capable of somewhat lower NO_x emission levels (100 ppm versus 200 ppm), the complexity and cost of control is much greater (about $100/kW versus $10/kW). Also, the OECD applications of this developmental technology are limited to oil and low sulfur coal. Based on EPRI pilot plant experience, if this flue gas treatment technology were required as best achievable NO_x reduction technology it would introduce a host of technical issues requiring resolution on high sulfur coal-fired plants. These include process chemistry, toxic emissions, solid wastes and reliability. Even if successful, the result would be much less cost effective than combustion control of NO_x and would encourage further premature and costly shutdowns of affected power plants.

11. I believe regulatory policy will have a major impact on life extension decisions. Our on-going analysis of the cost of life extension in the utility industry indicates a typical cost range of $100-300/kW for an additional 10-20 years of life without additional emission control. This cost analysis is highly site specific and will depend on the previous operating history of the generating unit as well as its future operating requirements. The present Clean Air Act already limits the amount of power plant refurbishment investment permitted before it is considered a major modification requiring NSPS. Under these conditions, it is also important to note that most coal-fired life extension candidate units over the remainder of this century are located in the high sulfur coal burning states of the midwest and midsouth. If these units are required to meet NSPS, they would typically be limited to only two control alternatives capable of meeting this level of SO_2 emission reduction - either flue gas scrubbing or, in some cases, AFBC conversion. Generally, AFBC conversion appears more cost effective as determined already by Northern States Power (NSP) and Wisconsin Electric Power Company (WEPCO). It is important to note, by comparison, that flue gas scrubbing will typically more than double the cost of life extension. It is unlikely that this investment can be justified under the economic disincentives now controlling regulated utilities.

Since near term electricity demand growth is relatively low in the midwest and midsouth, I believe that decisions to extend the life of older high sulfur coal burning plants will be the exception rather than the rule over the next decade unless some relaxation of the NSPS requirement is provided to permit more technological freedom of choice for lower cost emission control methods now under development. These could improve the cost effectiveness, of retrofit emission control by 100%, or more.

In the face of these constraints, I would expect more life extension to occur in oil and gas fired power generating units over the next decade where the cost of additional emission control is not required.

12. No, in my judgement the authority of Section III(j) to provide for extension of compliance schedules has not been effectively implemented by EPA because of the statutory requirements imposed on the process. These have effectively taken away incentives for utility industry personnel to request the waiver and have also apparently discouraged EPA because of the agency's difficulty in interpreting the statutory intent.

For example, construction of a new power plant will take between 5-10 years to complete. Thus, the waiver could end before the plant begins operation. Also, if the technology fails to comply with the letter of the law, retrofit additions of control technology would create an economic burden to the company and its rate payers for which no risk sharing provisions are available.

13. We estimate that the national average cost of FGD retrofit, assuming a conventional wet limestone FGD process designed to meet NSPS (90% SO_2 removal) would be 295 $/kW in 1986 $ assuming a moderate retrofit difficulty. The actual cost in $/kW will, however, vary depending on a number of factors. The cost will increase with higher sulfur content in the coal, more difficult retrofit situations, and smaller unit size. Those factors bring the range of retrofit costs from $190/kW to $450/kW in 1986 dollars.

The cost to scrub all facilities assumes that even hard-to-retrofit small units, and low sulfur coal units are scrubbed. By applying the FGD cost estimating procedures, detailed in EPRI's Report CS-3696, to the station retrofit difficulties tabulated in EPA's preliminary report of Contract NO. 68-01-6614, an average cost to scrub all of the nation's top 120 SO_2 emitting stations would be $341 $/kW in 1986 $.

If these estimates are applied to the 180 GW of unscrubbed capacity over 25 MW, the resulting capital cost for SO_2 control would be approximately $53-$61 billion (180 GW x $295-$341/kW). Operating costs (fixed and variable O&M including capital charges) associated with wet limestone scrubbers on 180 GW of coal-fired power plants would be approximately $21 billion annually ($918 \times 10^9$ kWh x $0.023/kWh = $21.1 billion /yr).

On the other hand, if the flexibility was available to use the range of less expensive developmental clean coal technologies, this compliance cost could be reduced significantly. In particular, a more cost effective retrofit emission reduction strategy would allow use of partial scrubbing and lower cost technologies e.g. (LIMB, FBC, induct sorbent injection, advanced FGD and advanced coal preparation/cleaning) to avoid depending on current, expensive FGD. EPRI calculates that the resulting cost savings under HR 4567 would be about $1 billion/yr. Under S 2203 the savings could be more than $10 billion/yr for SO_x and NO_x control combined.

14. Estimating the costs of implementing an acid rain reduction program can, of course, vary widely depending on the degree of emission reduction required, the schedule for compliance, the technologies allowed and demonstrated, whether the States will or can reduce emissions on a cost effective basis ($/ton SO_2 removed), and on the economic assumptions used in the analysis.

HR 4567 has been reviewed by several analysts, including Temple, Barker, Sloan (for EEI), ICF (for EPA), and OTA. The annualized compliance costs estimated by each are shown below:

$ Billion/Year

	TBS	ICF	OTA
Total Costs	9.2[a]/5.4[b]	3.5 - 6.2	3.8 - 4.9

a - 5 year levelized costs
b - 20 year levelized costs

Preliminary EPRI analyses to determine technical and cost implications indicate that the likely compliance cost is $4-$5 billion/year. Unfortunately, as indicated earlier, the cost saving opportunities to flexibly use new clean coal technology are largely eliminated by the ultimate NSPS level of control required statewide and the compliance schedule.

S 2293, on the other hand has not, to my knowledge, been analyzed as thoroughly from a cost of compliance standpoint. Our own preliminary analysis to determine the implications for control technology indicates that it will be extremely expensive. Based on the even more limited potential for application of developmental clean coal technology, it appears that the legislation would cost about $12 billion/yr. for SO_2 control and as much as $6 billion/yr for NO_x control. This would require a capital investment of $52 billion for SO_x control and about an additional $20 billion for NO_x control. The cost per ton of SO_2 controlled would be about $1100.

By comparison, it is interesting to note that if full flexibility were permitted to use retrofittable clean coal technology, both in terms of control level and schedule, the annual cost to achieve the same level of emission reduction could be reduced to \$6.6 billion. Similarly, the capital cost could be reduced to \$24 billion for SO_2 control and \$1.3 billion for NO_x control. This still, in my judgement, would represent a major diversion of resources inconsistent with current scientific evidence and delaying the more strategically effective introduction of clean coal technology in new plant and repowering applications.

15. This question is difficult to answer. We know, for example, that the acid in eastern precipitation is about 60% sulfuric, 35% nitric, and 5% other. Reducing just sulfur in the atmosphere may not, however, result in a corresponding reduction in acidity because a reduced atmospheric loading of sulfur could result in an increase in NO_2 oxidation to nitrates, hence, the nitric acid component of precipitation could increase, resulting in little change in acidity. We are still uncertain about the individual sulfur and nitrogen reactions that lead to rain acidity; we are even more uncertain about the effects of sulfur on nitrogen reactions and vice versa.

    We agree on what has been stated in the following sources on the composition of precipitation and we also agree on the contribution of potential precursors of emissions. The uncertainty is what effect reducing one precursor would have on the final acidity in precipitation.

    Sources: Research conducted by Dr. Steve Schwartz at Brookhaven National Laboratory and Dr. Jack Calvert at Ohio State University
    DOE MAP3S Program
    EPRI and EPA Emission Inventories

ATTACHMENT A

SENSITIVITY ANALYSIS OF ELECTRIC UTILITY SO_2 EMISSIONS IN THE U.S.

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A. INTRODUCTION

A central issue in setting future SO_2 emission standards for fossil fuel-fired industrial and electric utility boilers is whether SO_2 emissions will decrease, level off or increase in future years. The direction of future SO_2 emissions depends on complex interactions of regional growth rates of electricity demand, reserve margins, retirement and life extension of aging fossil fuel units, and application of national and local emission regulations.

This report presents a sensitivity analysis of regional and total U.S. SO_2 emissions from coal and oil-fired power plants over the period 1980 to 2030. Several scenarios are evaluated covering a range of energy demand growth rates and fossil plant life extension assumptions. The effort is an extension of earlier EPRI analyses reported in 1984 (1).

In summary, this analysis indicates that utility SO_2 emissions can be expected to continue to decline from 1980 levels in the future. This continues the downward trend in SO_2 emissions which began in the mid-1970s as summarized historically in Figure 1. In addition, 76% of the 185 GW of pre-NSPS coal-fired capacity in the U.S. without flue gas desulfurization (FGD) could remain in service beyond their normal 40 year service life without forcing SO_2 emissions to rise above current levels. This fraction is even higher in the Northeast and Midwest regions.

B. ASSUMPTIONS

The analysis was performed for five scenarios, as described in Table 1. Major assumptions of the Base Case include the most current NERC projections (2) of 2.3 percent average U.S. annual energy demand growth rate*, 20 percent planning reserve margin, no nuclear additions after 1994, and 40 year coal, oil and gas and 30 year nuclear plant life. The Base Case is not intended as the most realistic case, but rather a projection based on historical trends, against which sensitivity case analyses can be compared. Results of the Base Case analysis are shown in Figures 3 through 9 and Table 4. Regional annual energy demand growth rates are also based on 1985 NERC projections (2).

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*Note: 1985 NERC projections indicate that peak capacity (GW) and energy demand (GWh) will each grow at 2.3 percent annually during the period 1985 to 1994. The term annual energy demand will be used throughout this report and is applicable to both capacity (GW) and energy (GWh).

Four sensitivity cases were analyzed and represent variations from the Base Case as follows:

- Case A - 3.3 percent average U.S. annual energy demand growth rate (versus 2.3 percent in the Base Case).
- Case B - Limiting life extension of coal, oil, and gas steam units (from 40 to 60 years) such that regional SO_2 emissions in the year 2010 do not exceed 1985 levels.
- Case C - 100% life extension of all coal, oil, and gas-steam units from 40 to 60 years.
- Case D - Combination of A and C ("worst case" emissions projection).

Other key assumptions include:

- Region boundaries follow EPRI regional systems (3) (Figure 2).
- Regional retirement data for coal units through 1990 are based on EPRI's ERAM data base, updated from NERC Region Reports IE-411, April 1985 (Appendix B, Table B-1).
- Regional nuclear, hydroelectric, geothermal, other, and oil/gas-steam, combined cycle, and combustion turbine capacity data are based on 1985 NERC projections (2).
- Regional electricity imports and generation data for coal, nuclear hydroelectric, geothermal, other, and oil/gas-steam, combined cycle, and combustion turbine units are based on 1985 NERC projections (2).
- Regional coal heat contents, net fossil plant heat rates, and capacity factor data are based on the ERAM data base 1980 (Appendix B, Table B-1).
- Regional coal sulfur content data for 1984 and later years are based on power plant coal receipt data compiled by the National Coal Association (6).
- Regional combined oil and gas sulfur contents are based on 1985 NERC projections of oil and gas-fired power generation for the year 1994.
- 1979 New Source Performance Standards continue through the year 2030 on new units.
- With the exception of Figure 1, all emission quantities are in short tons.

- SO_2 removal is assumed to be 70 percent for existing retrofit FGD, 90 percent for new coal units with FGD, and 95 percent for advanced coal technologies.
- For comparison, uncontrolled SO_2 emissions are estimated for a hypothetical case of no state or federal SO_2 emission standards. For this uncontrolled case, the regional SO_2 emission factors are based on current coals, burned in existing units without FGD, but with a 0.5 percent increase in coal sulfur contents over 1980 levels.
- SO_2 emissions from all coal units without FGD were assumed to be reduced by 5 percent due to sulfur retention in the ash or rejection by the pulverizer.
- 1980 SO_2 emissions indicated in the figures and tables have been calibrated to the latest data available from EPA (4). The EPRI analysis has proceeded from this 1980 EPA foundation.
- Anticipated and mandated annual SO_2 emissions reductions in New York, Massachusetts, Michigan, Minnesota, and Wisconsin total 0.5 million tons in 1990 and 0.72 million tons in 1995 and were incorporated into the model by applying fuel switching to pre-NSPS coal units.

C. RESULTS

The results of the analysis are summarized in Figures 3 to 17. Figures 3 to 9 illustrate the sensitivity of total U.S. and regional annual SO_2 emissions to both peak demand growth rate (Cases A and D) and life extension (Cases B, C, and D). Figures 10 to 16 illustrate the impact of introducing advanced clean coal technologies (95 percent SO_2 control) on SO_2 emissions. Case C was chosen as the comparison case for the advanced coal technologies analysis. Figure 17 compares the EPRI analysis with a similar analysis by the Congressional Research Service.

Another factor potentially affecting future SO_2 emissions is the role of nuclear plants. A separate comparative analysis was made of two scenarios: (1) no nuclear life extension (all units retire at 30 years) plus a 5 year delay and 25 percent cancellation of units under construction (high SO_2 emission case); (2) 100% nuclear life extension of 30 years (from 30 to 60 years) and all units under construction are completed as scheduled (low SO_2 emissions case). Both scenarios assumed no new nuclear units after 1994. For all years analyzed from 1980 to 2030, the results showed only a slight difference (<2%) in SO_2 emissions between the two scenarios.

1. Increased Annual Energy Demand Growth Rate - Case A

Increasing the average peak demand growth rate from 2.3 to 3.3 % increases total U.S. SO_2 emissions from 13.6 to 13.8 million tons in the year 2000 and from 10.3 to 14.7 million tons in the year 2030, relative to the Base Case (Tables 4 and 5). Starting in 1980, total U.S. emissions steadily decrease in this case and reach a minimum of 10.6 million tons in 2015, and then begin to increase again through 2030. With slight variations, this same trend occurs in all U.S. regions analyzed as well. This decrease results both from the retirement at age 40 years of older, pre-NSPS plants with relatively high emissions and the state-mandated reductions of utility SO_2 emissions from the older coal units required by 1990 and 1995. The increase in emissions beyond 2020 occurs as new coal-based capacity is built to meet the high annual energy demand growth rate. Case A also assumes all fossil steam units retire at 40 years of age as in the Base Case.

2. Life Extension - Cases B, C, and D

a. General. Extended refurbishment of fossil plants is one of a set of strategic options being considered by many utilities for meeting future load demand projections. The potential of this approach is indicated by the fact that 55,000 MW of coal-fired and 40,000 MW of oil/gas capacity will exceed 40 years of age between now and the year 2000. The issue is important in evaluating future SO_2 emissions since most units being considered today for life extension are those built prior to promulgation of EPA New Source Performance Standards (pre-NSPS units). In 1980, these coal units emitted SO_2 at an average rate of about 3.1 pounds of SO_2 per million Btu heat input, whereas new units built under the 1971 NSPS averaged about 0.8 pounds of SO_2 per million Btu.

Rather than being retired at age 30 to 40 and replaced by lower emitting units, many of the pre-NSPS units may have their service life extended to 60 years or more.

The decision to implement extended refurbishment depends on the interaction of a variety of complex factors. Utilities most likely to consider life extension are those with a low reserve margin, good financial condition, efficient coal capacity, and average to high load growth. Preliminary analyses indicate capital costs for life extension are likely to be in the range of \$150/kW and \$300/kW, (exclusive of any additional emission control requirements) to confidently achieve a 20 to 25 year life extension. Thus, costs will play a major role in determining the amount of life extension, particularly if additional environmental controls are required by either local or federal regulations. A more detailed discussion of life extension is included in Appendix A to this report. As a result of these considerations, it appears unlikely that all aging capacity will be life-extended, even though it may be technically feasible to do so. Detailed feasibility studies will be required to make these decisions, and it is not yet practical to accurately predict the total amount of life extension that will be performed in the U.S. over the next 15 to 20 years. However, even under the most optimistic asumptions, life extension is not likely to exceed 75% of the candidate capacity, as indicated in Appendix A.

b. Limited Life Extension - Case B. In Case B, life extension of coal, oil and gas units without further SO_2 control was applied to the maximum extent consistent with not forcing SO_2 emissions above 1985 levels. The results are summarized in Tables 2 and 6 and plotted in Figures 3 to 9. Under these constraints, regional life extension fractions range from 70 to 100 percent in the Northeast, Southeast, East Central, and West Central regions to zero percent in the South Central and West Regions. Of the total 185 GW of pre-NSPS coal capacity in the U.S. without FGD on-line in 1990, 76% or 141 GW could be life extended to age 60 without forcing SO_2 emissions above their 1985 levels through at least 2010. Figures 3 through 9 illustrate SO_2 emission trends from 1980 to 2030. Only the West and South Central Regions show an increase in SO_2 emissions in 2030 compared to 1985. This is driven by expected demand growth, not life extension.

c. 100% Life Extension - Case C. Case C assumes that all coal, oil, and gas-steam units have a service life of 60 years, in comparison to the Base Case where all units are retired at 40 years. This assumption increases the capacity of coal units

Table 1

KEY ASSUMPTIONS FOR SENSITIVITY CASES

	Base Case	Case A High Growth	Case B Limited Life Extension	Case C 100% Life Extension	Case D A+C
Average U.S. Peak Demand Growth	2.3%	3.3%	2.3%	2.3%	3.3%
Nuclear Additions	None after 1993	None after 1993	None after 1983	None after 1993	None after 1993
Plant Life					
Coal-Steam	40	40	(a)	60	60
Oil and Gas-Steam	40	40	(a)	60	60
Nuclear	30	30	30	30	30
Fraction Life Extension	0%	0%	Varies by Region (See Table 2)	100%	100%

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a) The fraction life extension is set such that regional SO_2 emissions are equal in the years 1985 and 2010.

without FGD systems from 75 GW under the Base Case to 173 GW in the year 2010. Figures 10 to 16 show total U.S. and regional SO_2 emissions for Case C under three different emission scenarios:

- Uncontrolled SO_2 emissions in the absence of regulation.
- SO_2 emissions under 1979 NSPS assuming no introduction of advanced coal technologies (i.e., SO_2 control remains at 90% removal for all new units).
- SO_2 emissions based on introduction of advanced coal technologies, providing 100% of new additions after 1995, with SO_2 removals of 95%.

(1) NSPS Scenario

Under the 1979 NSPS scenario, projected annual U.S. SO_2 emissions decrease from 17.1 million tons in 1980 to 15.8 million tons in 1990, then increase and peak at 17.6 million tons in 2010. Emissions then begin to fall off due to retirement of plants without FGD that were life extended. Regionally, emissions trends are similar to the total U.S. case. For example, the East Central region reaches a peak of 6.1 million tons of SO_2 in 2010, compared to 1980 levels of 5.8 million tons, and then falls to 5.0 million tons in 2030. Notable exceptions to this trend occur in the West and South Central regions where emissions continue to rise. The apparent reason is that these regions have relatively less uncontrolled SO_2 capacity retiring, compared to other regions. Both regions also have relatively lower SO_2 emission rates and emissions compared to other U.S. regions in 1980. Thus, new capacity meeting NSPS is not significantly lower in emissions than older units, and emissions are much more sensitive to growth than in other regions.

(2) Advanced Coal Technologies Scenario

Another Case C sensitivity analysis was conducted, assuming that all new capacity additions after 1995 are advanced coal technologies capable of removing 95% SO_2. The results are shown in Figures 10 through 16 and Table 7. Advanced coal technologies include FBC, gasification/combined cycle and advanced coal with FGD. For the total U.S., SO_2 emissions peak in 2010 at 15.9 million tons in this case, compared to 17.6 million tons under the NSPS scenario. As shown in Figures 10 through 16, as more new advanced coal technology replaces retired units, the SO_2 emissions gap increases between the conventional coal (Case C) and 100% advanced coal emissions between 1980 and 2030, even in the South Central and West U.S. regions. Tables 5 through 8 also illustrate the impact of advanced coal technologies for Cases A, B, and D for the total U.S. Results for these cases are similar to those for Case C for both the entire U.S. and all regions.

d. 100% Life Extension and Increased Annual Energy Demand Growth Rate - Case D. Case D combines Cases A and C - annual energy demand growth rate of 3.3% and life extension of all fossil steam units to 60 years. Figures 3 through 9 and Table 8 illustrate the results of this "worst case" analysis. Total U.S. SO_2 emissions decrease to 15.6 million tons in 1990, then increase to 16.6 million tons in 2000 and 20.0 million tons in 2030. Regionally, emissions tend to increase gradually over time, except in the Northeast, where emissions are trending slightly downward after 2020. Emissions appear to level off in the East Central and West Central regions after 2025.

D. COMPARISON TO CONGRESSIONAL RESEARCH SERVICE ANALYSIS

During 1985, a report published by the Congressional Research Service (CRS) (5) concluded that utility SO_2 emissions will continue to increase through the year 2030, unless the New Source Performance Standards for SO_2 are tightened from 90 to 95 percent SO_2 removal. Such a conclusion can be achieved only by assuming demand growth rates and life extension impacts which substantially exceed current probable projections and are similar to the EPRI Case D ("worst case") assumptions.

Table 3 compares the EPRI Case D and CRS assumptions, and Tables 8 and 9 show total annual U.S. utility SO_2 emissions for EPRI Case D and CRS assumptions for the period 1980 to 2030. EPRI Case D (worst case SO_2 emissions) is closest to the CRS assumptions, except for small differences in peak demand growth rate (3.3% EPRI vs 3.1% CRS), fuel sulfur contents, and capacity factors. In addition, for fuel sulfur content and capacity factors, the EPRI analysis used documented utility plant data, whereas CRS used average assumed values for the entire U.S.

The results are compared with the actual CRS projections in Figure 17. Case D and the CRS case yielded similar projections of SO_2 emissions over the period 1980 to 2030. However, both projections, generated using the EPRI model, lag behind the actual CRS projection after the year 1995, and the difference reaches 20 to 25 percent of the CRS estimate by 2030. The primary reasons appear to be the relatively high fixed capacity factor (60 percent) and possibly lower FGD SO_2 removal efficiency assumed by CRS for coal-steam units. In the EPRI model, the coal-steam unit capacity factors are determined by energy demand, and the overall capacity factor typically ranged between 52 and 56 percent. CRS did not state the level of SO_2 removal efficiency assumed for FGD in their report, but based on stated assumptions for coal sulfur and heat contents, net capacity and heat rate, and capacity factors, the SO_2 removal efficiency was estimated to be 80 to 85 percent. Thus it appears that CRS overestimated both power generation and SO_2 emission factors for coal-steam units.

E. CONCLUSIONS

- Under current NERC growth projections of annual energy demand and capacity, Base Case (no life extension) utility SO_2 emissions are projected to decrease nationally from the 1980 level of 17.1 million tons to about 10 million tons in 2030. On a regional basis, only the West and South Central regions indicate probable increases over present levels at Base Case conditions.

- Future SO_2 emissions can be affected by life extension. Analyses indicate, however, that a high degree of life extension can be accommodated without forcing SO_2 emissions to rise from 1985 levels. Exceptions are in the South Central and West regions.

- Based on the results of this analysis, about 76% of 1990 U.S. pre-NSPS coal-fired generating capacity without FGD could be life extended to 60 years without forcing SO_2 emissions to rise above 1985 levels. On a regional basis, 70 percent or more of capacity in the Northeast, East Central, Southeast and West Central regions can have service life extended without an emission increase. From a practical standpoint, it is therefore unlikely that SO_2 emission growth should act as a barrier to life extension in these four regions.

- An increase in energy demand growth rate from 2.3 to 3.3 percent annually could significantly affect future SO_2 emissions. If all fossil units are retired at 40 years under this scenario, SO_2 emissions generally decrease until the year 2020 and then begin to climb rapidly both nationally and in most U.S. regions. Combined with 100% life extension, a 3.3% growth rate produces a continuous rise in SO_2 emissions nationally and in most regions. These assumptions substantially exceed expected conditions in the utility industry and thus represent a "worst case" projection.

- Significant regional differences were noted in the various cases analyzed. Under all cases, SO_2 emissions in the South Central and West regions tend to increase over time. The reason appears to be that SO_2 emission rates in these areas are currently relatively low because capacity is generally newer and the units burn lower sulfur fuel. Thus, even when meeting NSPS, addition of new capacity tends to cause emissions to rise. In the higher sulfur East Central region, emissions decrease or remain relatively flat under all cases. The reason appears to be that the population of boilers is older, load growth is relatively low, and the SO_2 emissions from new boilers meeting NSPS are substantially lower than those from older existing units.

- The results of all analyses in this report are based on the most current information available for future growth and generating mix of the electric utility industry. While the near future (0 to 10 years) can be predicted with some confidence, the results become less robust further into the future. Thus, given the uncertainties in predicting future load growth, generating mix, fuel prices and availability, etc., the SO_2 emissions shown in this report beyond 2000, should be considered as an indication of possible trends based on continuance of the identified assumptions.

- As shown in Case C (Figures 10-16), capacity additions of advanced clean coal technologies could significantly reduce SO_2 emissions from currently projected levels. It is also important to note again that none of the cases analyzed assumes any new nuclear capacity additions beyond those currently under construction. Thus, if nuclear power production is expanded in the future, it would further reduce these projections, particularly after 2000.

- The Congressional Research Service (CRS) projection assumes higher levels of demand growth, life extension, capacity factor, and SO_2 emission rate than anticipated by the utility industry. It thus results in an unrealistically high forecast of future SO_2 emissions.

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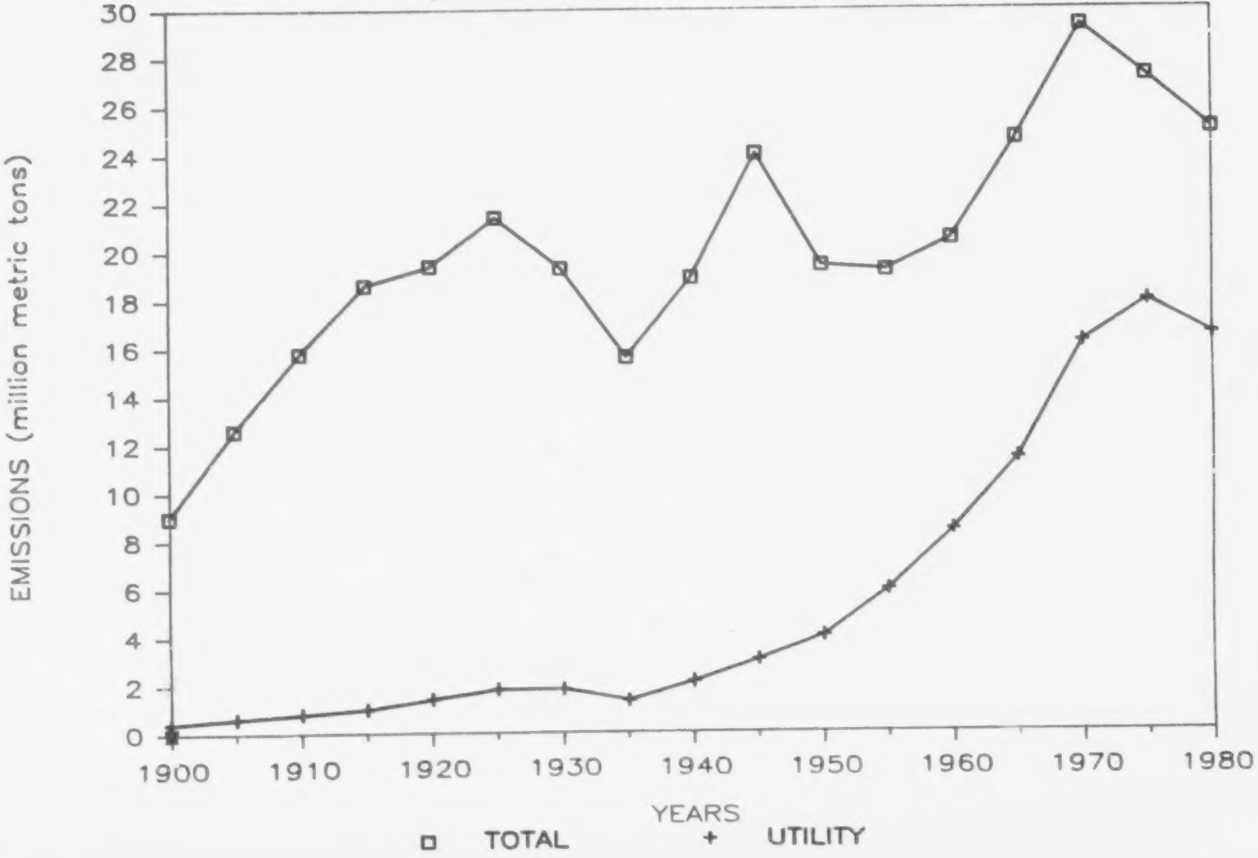

HISTORIC U.S. SO2 EMISSIONS

(EPA-600/S7-85-009, May 1985)

Table 2

Life Extension for Equal SO_2 Emissions
In 1985 and 2010 - Case B

Region	Peak Demand Growth Rate	Percent Life Extension[a)]	Total Coal, Oil, and Gas Steam Capacity in 1990 (GW)	1985 and 2010 Annual SO_2 Emissions (Million Tons)
NE	1.4%	100	62.4	2.2
SE	2.7	71	84.7	4.0
EC	2.1	82	86.8	5.7
SC	1.8	38 [b)]	100.0	1.6
WC	3.1	100	51.7	2.5
W	2.3	1 [b)]	53.4	0.5
Average U.S.	2.3%	56%	439	16.5
Pre-NSPS Coal Units Without FGD		76%	185	

a) Percentage of all coal, oil, and gas-steam units in 1990 which could be retired at age 60 without forcing SO_2 emissions above 1985 levels.

b) Even with zero life extension, predicted SO_2 emissions from coal and oil-steam units increase between 1985 and 2010 in the South Central and West regions; percentage shown corresponds to gas-steam capacity, which can be extended to 60 year life without increasing SO_2 emissions.

Table 3

COMPARISON OF EPRI "WORST CASE" AND CRS ASSUMPTIONS

	EPRI Case D	CRS Assumptions	
Peak Demand Growth Rate	3.3%	3.1%	
Nuclear Additions	None after 1993	None after 1995	
Plant Life (yrs)			
Coal	60	60	
Oil	60	60	
Nuclear	30	30	
Fuel Sulfur Content:			
Coal - Pre NSPS Units	0.54-2.34% for 6 regions[b]		1.5%
1971 NSPS Units	0.40-0.73% " " "		0.5%
Oil/Gas Composite	0.03-0.99% for 6 regions[b]		1.0%/0%
FGD SO$_2$ Removal	90%	90%	90%[a]
Capacity Factor - Coal	50-64% for 6 regions[b]		60%
Oil	30%	30%	30%

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a) Not specified by CRS

b) Based on EPRI-ERAM Data Base

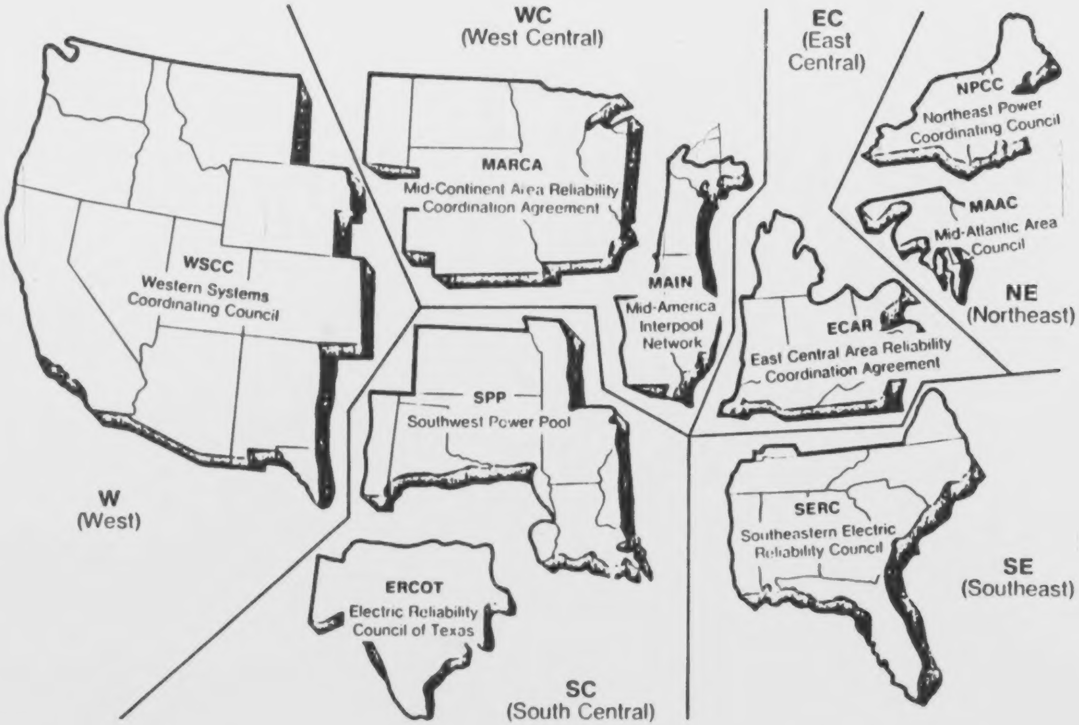


Figure 2 EPRI Regional Systems. Six Regions Based on National Electric Reliability Council Regions (contiguous U.S.)

Figure 3

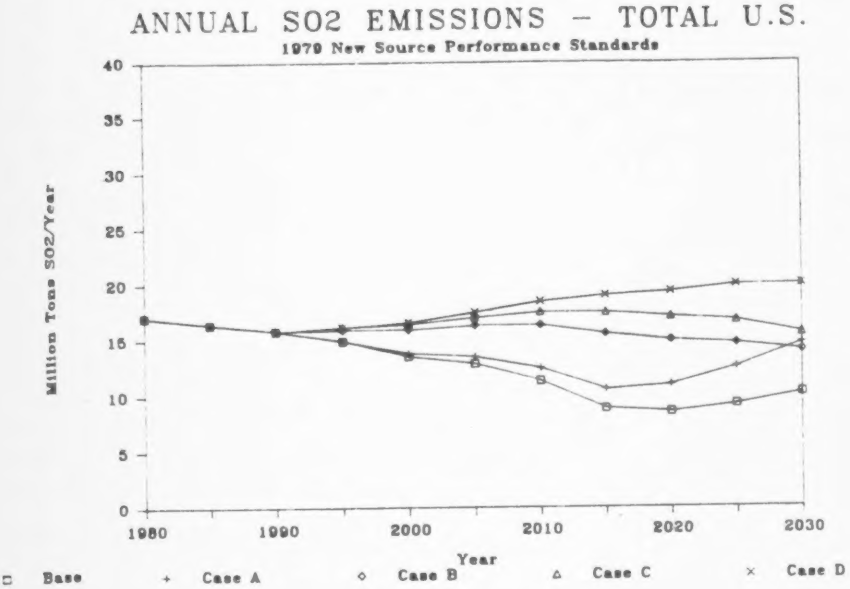
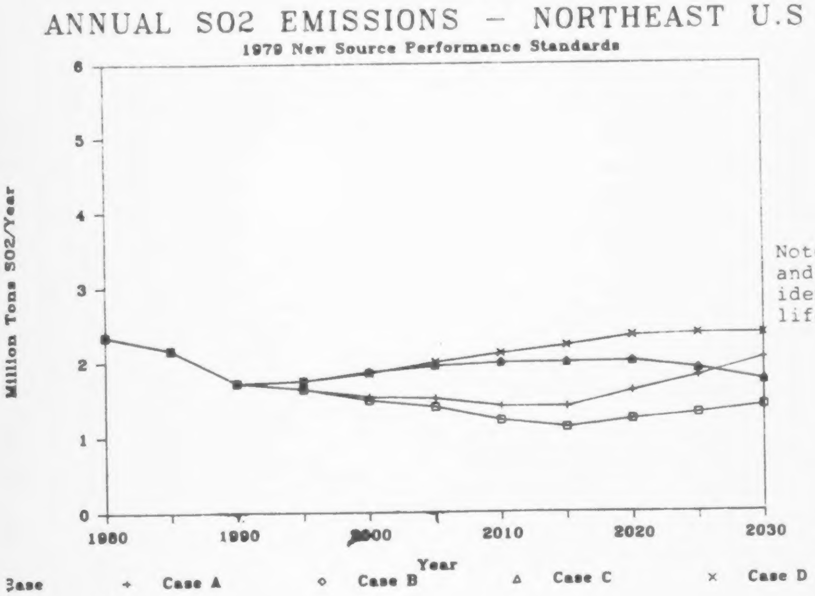


Figure 4



Note: Cas
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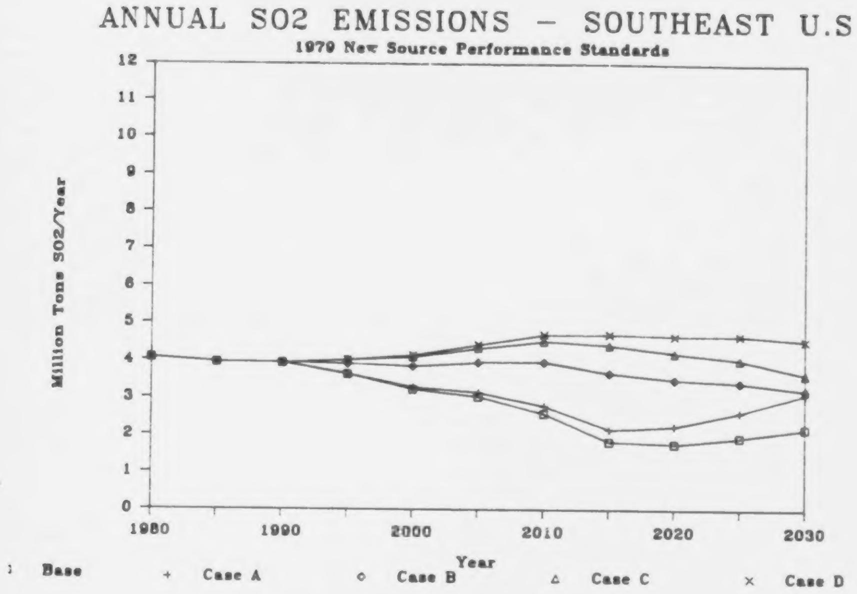
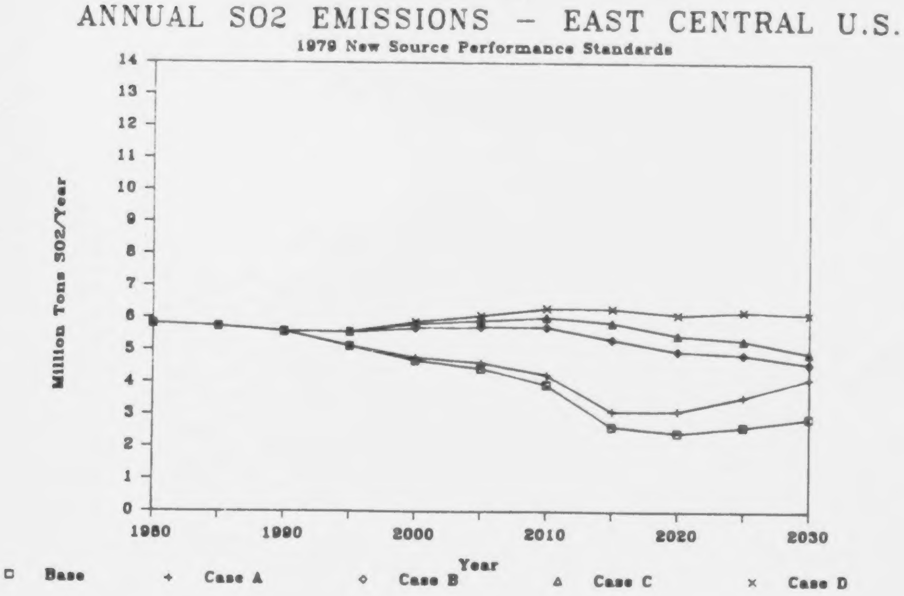
Figure 5



ANNUAL SO2 EMISSIONS - SOUTHEAST U.S

1979 New Source Performance Standards

Figure 6



ANNUAL SO2 EMISSIONS - EAST CENTRAL U.S.

1979 New Source Performance Standards

Figure 7

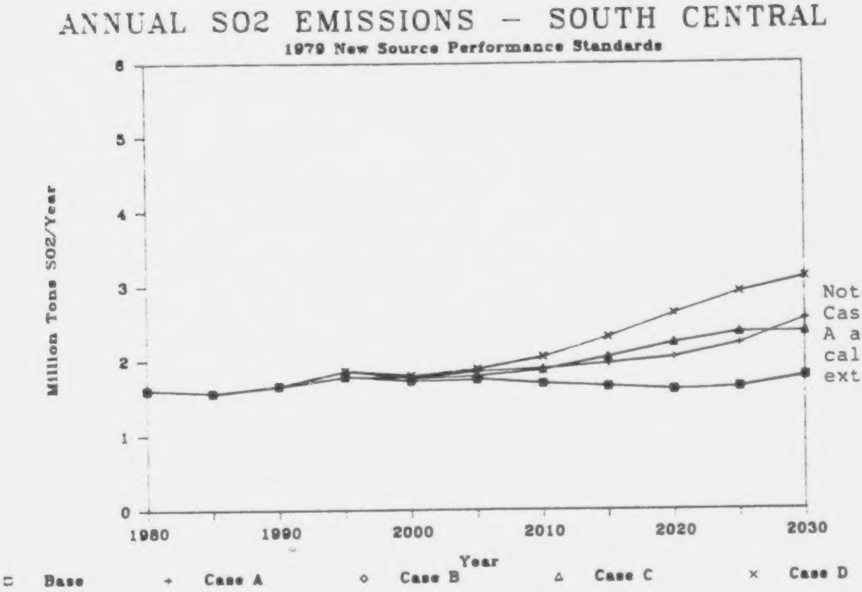


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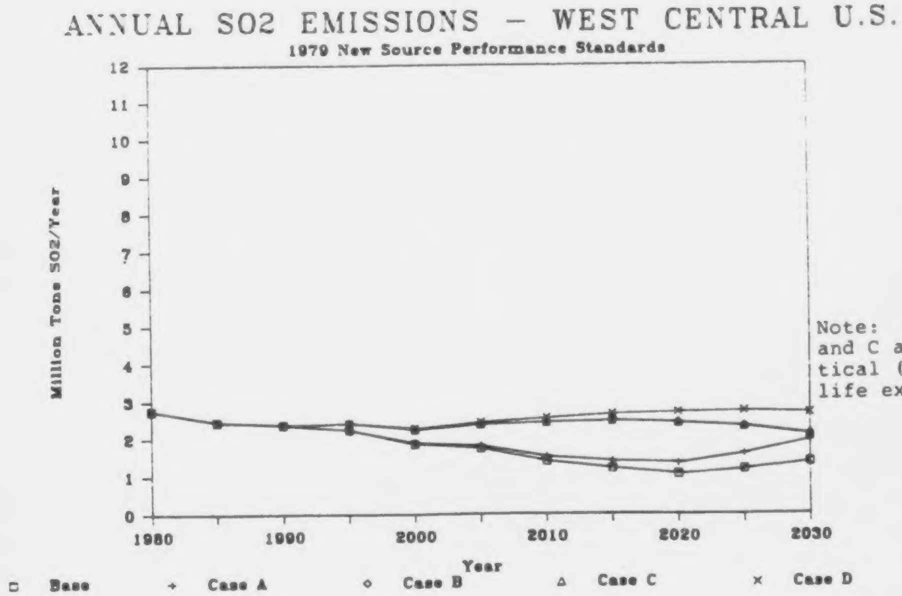
Figure 8



Note: Cas
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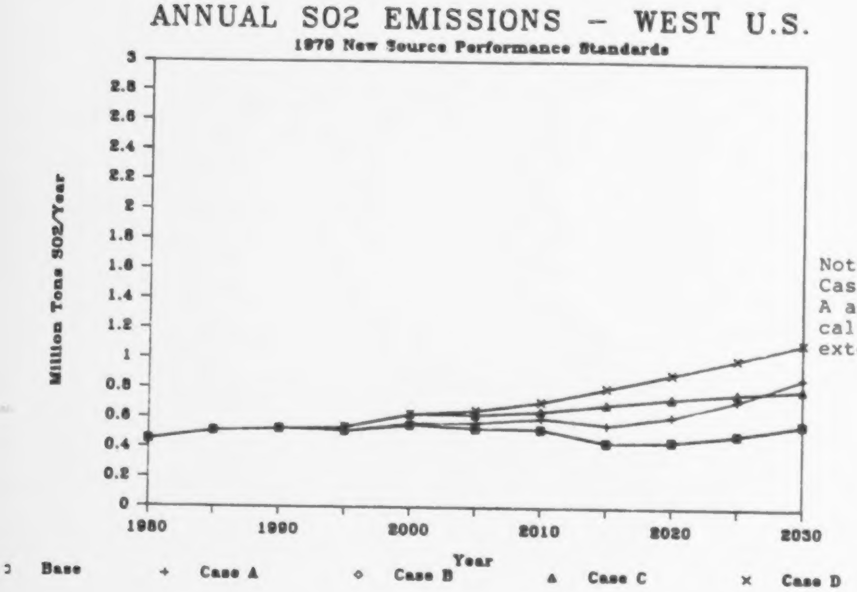
life exten

Figure 9



Note: Base Case and Case A are identical (0% life extension)

Figure 10

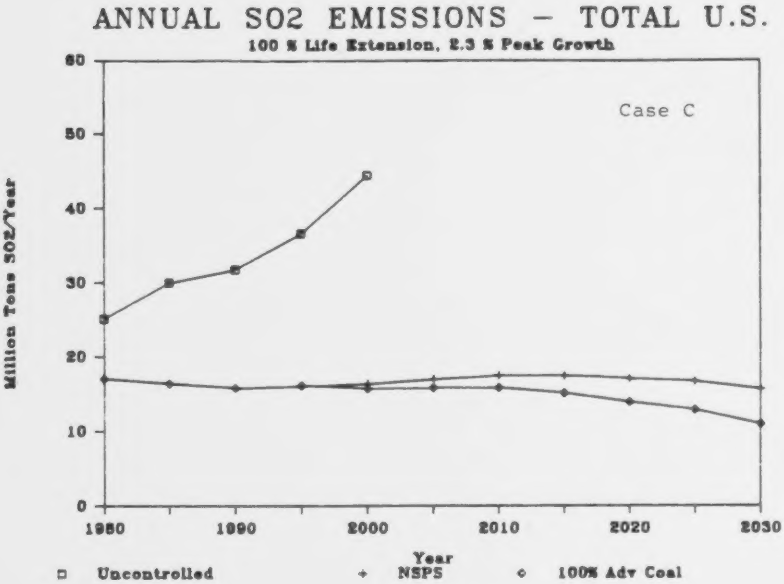


Figure 11

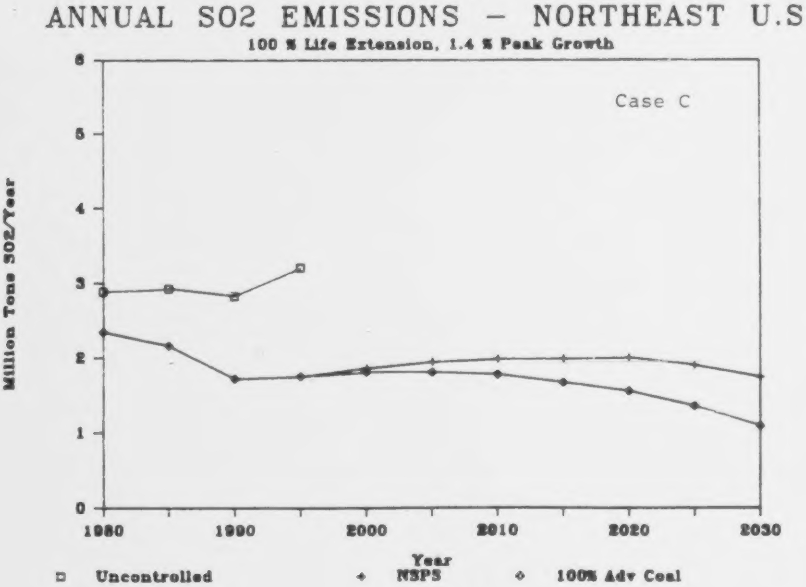


Figure 12

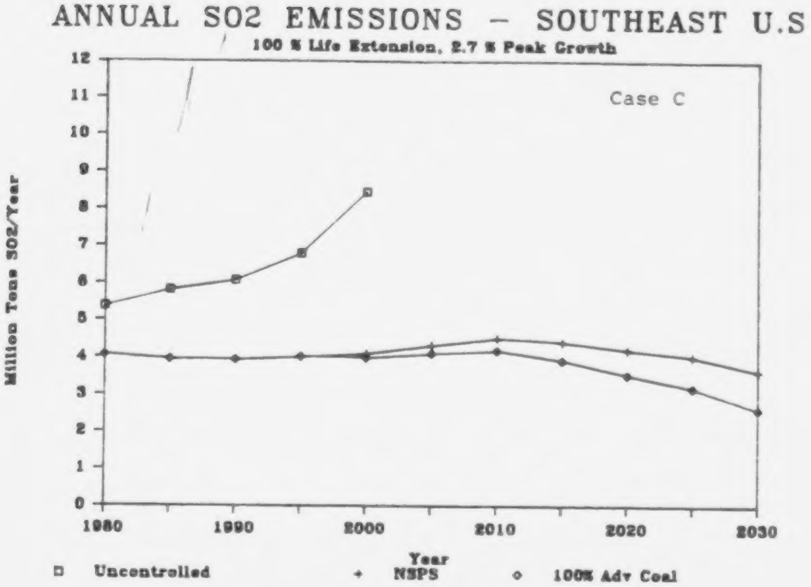


Figure 13

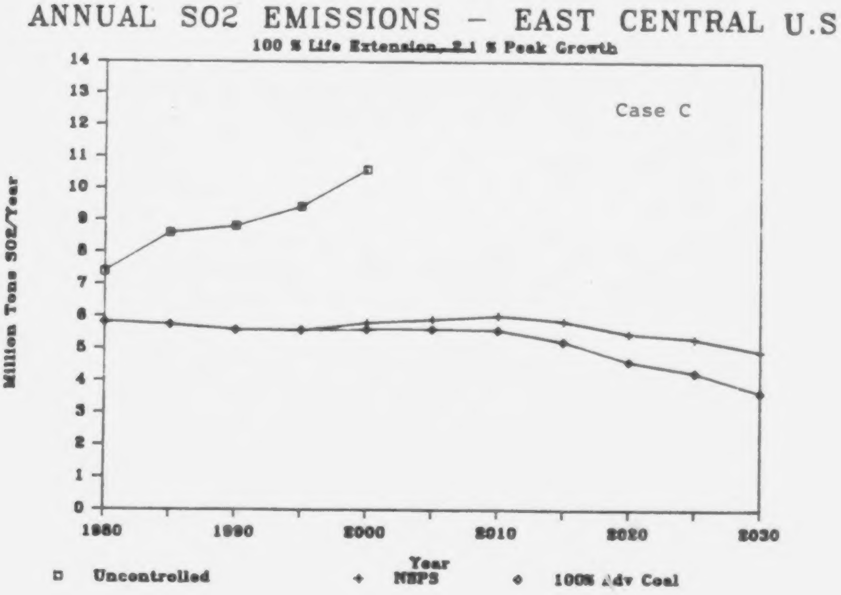
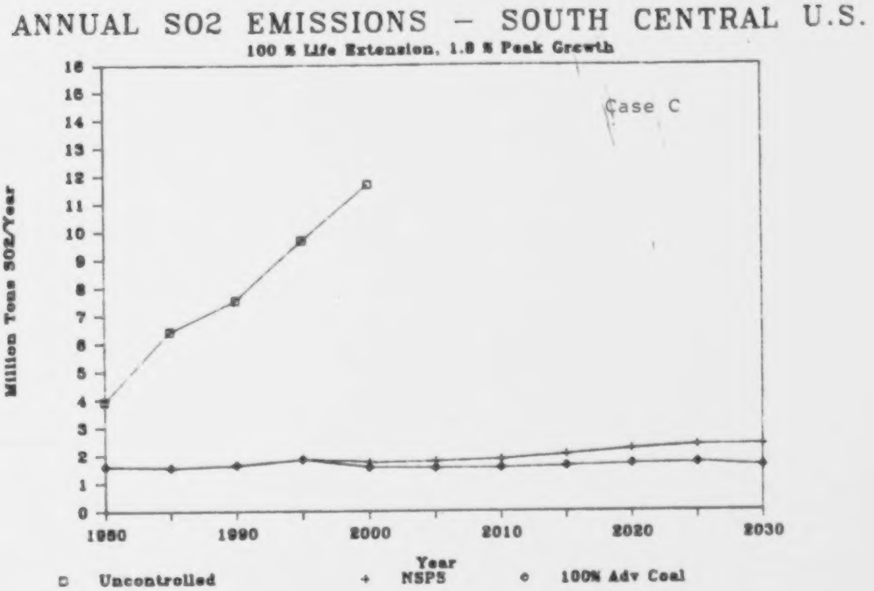


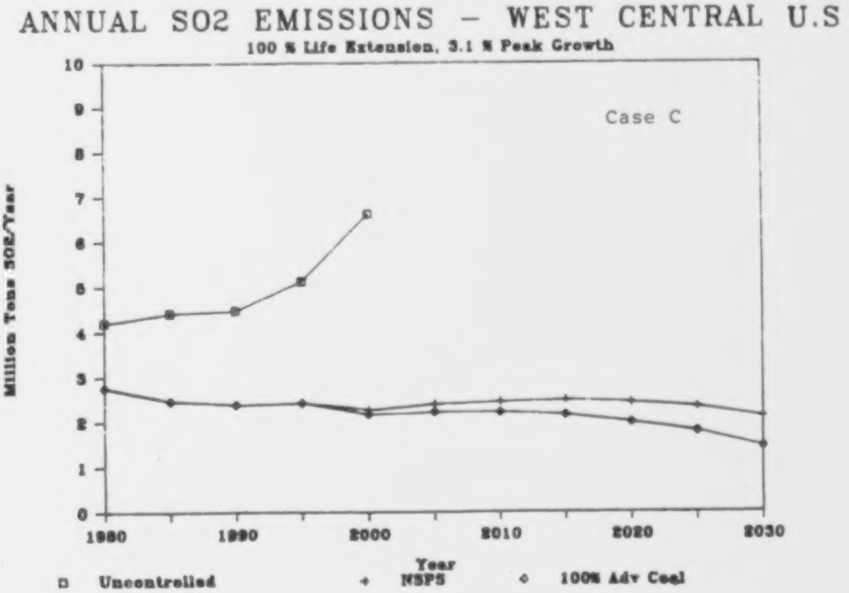
Figure 14



ANNUAL SO2 EMISSIONS – SOUTH CENTRAL U.S.

100 % Life Extension, 1.8 % Peak Growth

Figure 15



ANNUAL SO2 EMISSIONS – WEST CENTRAL U.S

100 % Life Extension, 3.1 % Peak Growth

Figure 16

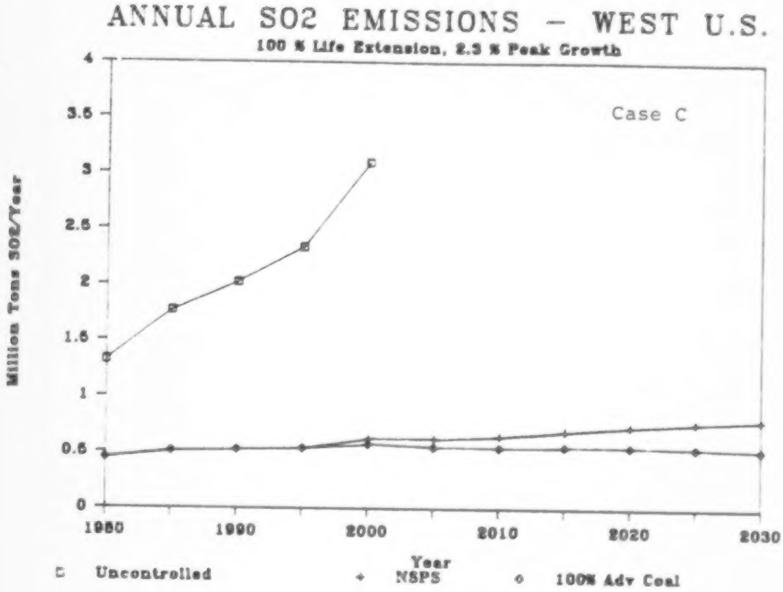


Figure 17

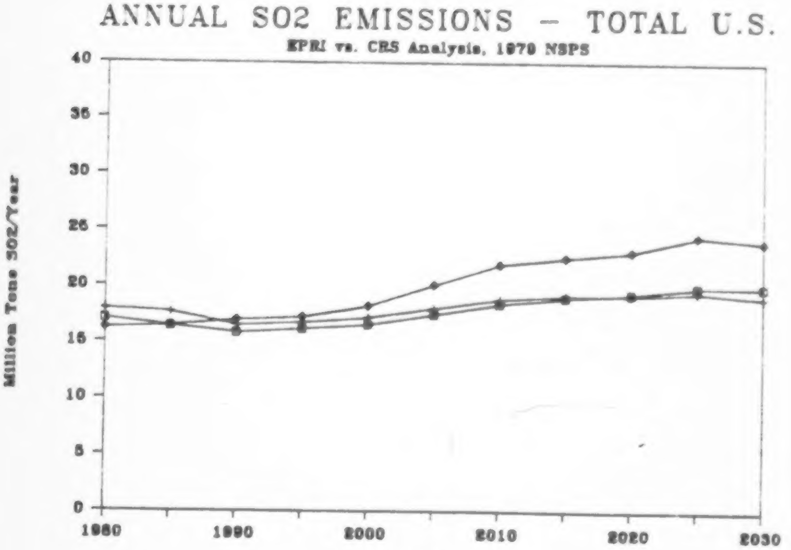


Table 4

05-Mar-86

PROJECTED SO2 EMISSIONS BY REGION

Contiguous United States   Base Case
Retired at Age 60: 0%   Peak Demand Growth %: 2.3
SO2 Emissions (Mtons/yr)

Year	Total Uncon- trolled	Total 100 % Adv Coa	NSPS by Region: NE	SE	EC	SC	WC	W	Total NSPS
1980	25.2	17.1	2.3	4.1	5.8	1.6	2.8	0.5	17.1
1985	30.0	16.4	2.2	4.0	5.8	1.6	2.5	0.5	16.4
1990	31.8	15.8	1.7	3.9	5.6	1.7	2.4	0.5	15.8
1995	38.0	14.9	1.6	3.6	5.1	1.8	2.2	0.5	14.9
2000	46.3	12.5	1.5	3.2	4.7	1.7	1.9	0.6	13.6
2005	58.1	11.2	1.4	3.0	4.4	1.8	1.8	0.5	12.9
2010	69.9	9.0	1.2	2.6	3.9	1.7	1.4	0.5	11.4
2015	85.3	5.6	1.1	1.8	2.6	1.7	1.2	0.4	8.9
2020	101.2	4.5	1.2	1.8	2.5	1.6	1.1	0.4	8.6
2025	114.4	4.5	1.3	2.0	2.7	1.6	1.2	0.5	9.2
2030	120.5	4.9	1.4	2.2	2.9	1.8	1.4	0.6	10.3

SO2 EMISSIONS SUMMARY

Contiguous United States - Base Case
Retired at Age 60: 0%   Peak Demand Growth %: 2.3
SO2 Emissions (Mtons/yr)

Year	Uncontrolled Coal Steam	Uncontrolled Oil St,CT	Uncontrolled Total Fossil	Current NSPS Coal Steam	Current NSPS Oil St,CT	Current NSPS Total Fossil	100 % Adv Coal Coal Steam	100 % Adv Coal Oil St,CT	100 % Adv Coal Total Fossil
1980	23.7	1.4	25.2	15.6	1.4	17.1	15.6	1.4	17.1
1985	29.2	0.8	30.0	15.6	0.8	16.4	15.6	0.8	16.4
1990	31.2	0.6	31.8	15.2	0.6	15.8	15.2	0.6	15.8
1995	37.3	0.7	38.0	14.3	0.7	14.9	14.3	0.7	14.9
2000	45.7	0.6	46.3	13.0	0.6	13.6	11.9	0.6	12.5
2005	57.6	0.5	58.1	12.5	0.5	12.9	10.7	0.5	11.2
2010	69.5	0.4	69.9	11.0	0.4	11.4	8.6	0.4	9.0
2015	85.1	0.2	85.3	8.7	0.2	8.9	5.4	0.2	5.6
2020	101.1	0.1	101.2	8.5	0.1	8.6	4.4	0.1	4.5
2025	114.4	.0	114.4	9.2	.0	9.2	4.4	.0	4.5
2030	120.5	.0	120.5	10.2	.0	10.3	4.9	.0	4.9

PROJECTED SO2 EMISSIONS - NSPS

Contiguous United States - Base Case
Retired at Age 60: 0%   Peak Demand Growth %: 2.3
SO2 Emissions (Mtons/yr)

Year	Coal-Steam wo FGD	71NSPS wo FGD	with FGD	Adされd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	14.9	0.3	0.1	0.0	0.3	15.64	1.4	.0	17.08
1985	14.0	0.9	0.3	0.0	0.3	15.50	0.8	.0	16.43
1990	13.4	1.1	0.4	0.0	0.3	15.23	0.6	.0	15.83
1995	11.8	1.1	1.1	0.0	0.3	14.29	0.6	.0	14.95
2000	9.6	1.1	2.0	0.0	0.3	13.08	0.5	.0	13.56
2005	8.0	1.0	3.2	0.0	0.2	12.45	0.4	.0	12.91
2010	5.4	1.0	4.5	0.0	0.1	10.99	0.4	.0	11.38
2015	1.4	1.0	6.3	0.0	.0	8.71	0.2	.0	8.98
2020	.0	0.7	7.8	0.0	.0	8.52	.0	.0	8.58
2025	.0	0.2	9.0	0.0	.0	9.22	.0	.0	9.25
2030	.0	0.1	10.1	0.0	.0	10.23	.0	.0	10.26

1.0247 1.3233 Calibration Factors
15.64 1.4444

PROJECTED POWER GENERATION

Contiguous United States - Base Case
Retired at Age 60: 0%   Peak Demand Growth %: 2.3
Power Generation (BkWh/yr)

Year	Coal-Steam wo FGD	71NSPS wo FGD	with FGD	Added Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	916.3	69.4	97.3	0.0	61.2	1139.4	547.5	14.5	1701.5
1985	928.0	190.7	194.5	0.0	62.1	1375.2	352.2	6.0	1733.4
1990	908.7	225.0	268.0	0.0	62.3	1463.9	293.2	8.0	1765.1
1995	801.9	237.4	626.3	0.0	57.3	1723.0	268.0	10.7	2001.7
2000	653.5	226.7	1196.1	0.0	56.3	2132.6	226.0	11.0	2371.2
2005	539.5	221.4	1914.7	0.0	37.0	2712.6	178.3	13.1	2904.0
2010	356.1	215.6	2683.6	0.0	23.5	3278.8	118.1	14.5	3411.5
2015	88.4	212.3	3712.5	0.0	9.3	4022.6	36.7	16.2	4075.4
2020	.0	157.2	4645.8	0.0	.0	4803.0	7.1	18.0	4828.0
2025	.0	40.5	5421.7	0.0	.0	5462.2	.0	20.0	5482.2
2030	.0	17.6	6139.1	0.0	.0	6156.7	.0	22.3	6179.0

PROJECTED POWER GENERATING CAPACITY

Contiguous United States - Base Case
Retired at Age 60: 0%   Peak Demand Growth %: 2.3
Generating Capacity (GW)

Year	Coal-Steam wo FGD	71NSPS wo FGD	with FGD	Added Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	187.1	14.9	16.9	0.0	12.0	230.9	153.2	40.2	424.2
1985	186.1	45.5	37.0	0.0	12.0	280.7	145.6	39.3	465.6
1990	184.9	51.9	50.9	0.0	12.0	299.7	139.2	40.9	479.9
1995	161.8	55.3	121.6	0.0	11.2	349.8	112.3	44.9	507.0
2000	135.4	56.6	242.6	0.0	10.8	445.3	94.7	50.0	590.0
2005	113.2	56.6	399.2	0.0	7.3	576.2	74.9	55.6	706.7
2010	75.0	56.6	572.1	0.0	4.7	708.4	51.4	62.0	821.8
2015	19.3	56.6	802.2	0.0	1.9	879.9	17.9	69.2	967.0
2020	.0	41.7	1008.6	0.0	.0	1050.3	3.3	77.2	1130.9
2025	.0	11.0	1184.9	0.0	.0	1195.9	.0	86.3	1282.2
2030	.0	4.7	1344.1	0.0	.0	1348.7	.0	96.5	1445.2

Table 5

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PROJECTED SO2 EMISSIONS BY REGION

Contiguous United States - Case A - High Growth
Retired at Age 60: 0% Peak Demand Growth %: 3.3
SO2 Emissions (Mtons/yr)

Year	Total Uncon-trolled	Total 100 % Adv Coa	NE	SE	EC	SC	WC	W	Total NSPS
1980	25.2	17.1	2.3	4.1	5.8	1.6	2.8	0.5	17.1
1985	30.0	16.4	2.2	4.0	5.8	1.6	2.5	0.5	16.4
1990	31.8	15.0	1.7	3.9	5.6	1.7	2.4	0.5	15.8
1995	38.6	15.0	1.6	3.6	5.1	1.8	2.2	0.5	15.0
2000	50.5	12.6	1.5	3.3	4.8	1.8	1.9	0.6	13.8
2005	66.8	11.5	1.5	3.1	4.6	1.9	1.8	0.6	13.5
2010	84.4	9.5	1.4	2.0	4.3	1.9	1.5	0.6	12.5
2015	107.2	6.4	1.4	2.2	3.1	2.0	1.4	0.6	10.6
2020	132.2	5.6	1.6	2.3	3.1	2.0	1.4	0.6	11.8
2025	156.9	6.1	1.8	2.6	3.6	2.2	1.6	0.7	12.6
2030	185.2	7.0	2.0	3.1	4.2	2.6	2.0	0.9	14.7

(NE through W: NSPS by Region)

SO2 EMISSIONS SUMMARY

Contiguous United States - Case A - High Growth
Retired at Age 60: 0% Peak Demand Growth %: 3.3
SO2 Emissions (Mtons/yr)

	Uncontrolled			Current NSPS			100 % Adv Coal		
Year	Coal Steam	Oil St,CT	Total Fossil	Coal Steam	Oil St,CT	Total Fossil	Coal Steam	Oil St,CT	Total Fossil
1980	23.7	1.4	25.2	15.6	1.4	17.1	15.6	1.4	17.1
1985	29.2	0.8	30.0	15.6	0.8	16.4	15.6	0.8	16.4
1990	31.2	0.6	31.8	15.2	0.6	15.8	15.2	0.6	15.8
1995	37.9	0.7	38.6	14.3	0.7	15.0	14.3	0.7	15.0
2000	49.9	0.6	50.5	13.3	0.6	13.8	12.0	0.6	12.6
2005	66.4	0.5	66.8	13.1	0.5	13.5	11.0	0.5	11.5
2010	84.0	0.4	84.4	12.1	0.4	12.5	9.1	0.4	9.5
2015	107.0	0.2	107.2	10.4	0.2	10.6	6.2	0.2	6.4
2020	132.2	0.1	132.2	11.0	0.1	11.0	5.6	0.1	5.6
2025	156.9	.0	156.9	12.6	0	12.6	6.0	.0	6.1
2030	185.1	0.1	185.2	14.7	0.1	14.7	6.9	0.1	7.0

PROJECTED SO2 EMISSIONS - NSPS

Contiguous United States - Case A - High Growth
Retired at Age 60: 0% Peak Demand Growth %: 3.3
SO2 Emissions (Mtons/yr)

	Coal Steam								
Year	wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	14.9	0.3	0.1	0.0	0.3	15.64	1.4	.0	17.08
1985	14.0	0.9	0.3	0.0	0.3	15.58	0.8	.0	16.43
1990	13.4	1.1	0.4	0.0	0.3	15.23	0.6	.0	15.83
1995	11.8	1.1	1.1	0.0	0.3	14.32	0.6	.0	14.97
2000	9.6	1.1	2.4	0.0	0.3	13.26	0.5	.0	13.83
2005	8.0	1.0	3.9	0.0	0.1	13.08	0.4	.0	13.54
2010	5.3	1.0	5.7	0.0	0.1	12.10	0.4	.0	12.49
2015	1.4	1.0	8.0	0.0	.0	10.42	0.2	.0	10.62
2020	.0	0.7	10.2	0.0	0	10.97	.0	.0	11.04
2025	.0	0.2	12.4	0.0	.0	12.56	.0	.0	12.61
2030	0	0.1	14.6	0.0	.0	14.67	.0	0.1	14.73

1.0247 1.3233 Calibration Factors
15.64 1.4444

PROJECTED POWER GENERATION

Contiguous United States - Case A - High Growth
Retired at Age 60: 0% Peak Demand Growth %: 3.3
Power Generation (BkWh/yr)

	Coal Steam								
Year	wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	916.3	69.4	92.5	0.0	61.2	1139.4	547.5	14.5	1701.5
1985	920.0	198.7	194.5	0.0	67.1	1375.2	352.2	6.0	1733.4
1990	908.7	225.0	268.0	0.0	62.3	1463.9	293.2	8.0	1765.1
1995	808.0	236.6	650.7	0.0	57.1	1752.4	268.0	10.8	2031.2
2000	648.3	224.1	1406.4	0.0	55.4	2334.2	226.8	12.5	2573.4
2005	534.6	218.4	2346.6	0.0	36.4	3135.9	178.3	14.6	3328.8
2010	352.8	213.0	3395.0	0.0	23.2	3984.0	118.1	17.0	4119.8
2015	87.7	210.0	4778.0	0.0	9.2	5085.7	36.7	19.8	5142.3
2020	0	155.2	6159.5	0.0	0	6314.7	7.1	23.2	6345.0
2025	0	40.1	7493.9	0.0	.0	7534.0	.0	27.1	7561.1
2030	.0	17.3	8907.2	0.0	0	8924.4	.0	31.7	8956.1

PROJECTED POWER GENERATING CAPACITY

Contiguous United States - Case A - High Growth
Retired at Age 60: 0% Peak Demand Growth %: 3.3
Generating Capacity (GW)

	Coal-Steam								
Year	wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	187.1	14.9	16.9	0.0	12.0	230.9	153.2	40.2	424.2
1985	186.1	45.5	37.0	0.0	12.0	280.7	145.6	39.3	465.6
1990	184.9	51.9	50.9	0.0	12.0	299.7	139.2	40.9	479.9
1995	161.8	55.3	128.3	0.0	11.2	356.5	112.3	45.3	514.1
2000	135.4	56.6	288.2	0.0	10.8	491.0	94.7	53.0	638.6
2005	113.2	56.6	494.9	0.0	7.3	672.0	74.9	61.9	808.8
2010	75.0	56.6	731.8	0.0	4.7	868.1	51.4	72.5	991.9
2015	19.3	56.6	1042.6	0.0	1.9	1120.3	17.9	84.9	1223.1
2020	.0	41.7	1350.3	0.0	.0	1392.1	3.3	99.5	1494.8
2025	.0	11.0	1653.0	0.0	.0	1664.0	.0	116.7	1780.7
2030	.0	4.7	1969.3	0.0	.0	1974.0	.0	137.0	2110.9

Table 6

05-Mar-86

PROJECTED SO2 EMISSIONS BY REGION
Contiguous United States - Case B - Limited Life Extension
Retired at Age 60: 50% Peak Demand Growth %: 2.3
SO2 Emissions (Mtons/yr)

Year	Total Uncon-trolled	Total 100 % Adv Coal	NSPS by Region: NE	SE	EC	SC	WC	W	Total NSPS
1980	25.2	17.1	2.3	4.1	5.8	1.6	2.8	0.5	17.1
1985	30.0	16.4	2.2	4.0	5.8	1.6	2.5	0.5	16.4
1990	31.8	15.8	1.7	3.9	5.6	1.7	2.4	0.5	15.8
1995	37.8	16.0	1.8	3.9	5.6	1.8	2.4	0.5	16.0
2000	46.0	15.1	1.9	3.8	5.7	1.7	2.3	0.6	16.0
2005	57.6	15.0	2.0	4.0	5.7	1.8	2.4	0.5	16.3
2010	69.3	14.5	2.0	4.0	5.7	1.7	2.5	0.5	16.4
2015	84.6	12.9	2.0	3.7	5.4	1.7	2.5	0.4	15.6
2020	100.4	11.5	2.0	3.5	5.0	1.6	2.4	0.4	15.0
2025	113.8	10.5	1.9	3.4	4.9	1.6	2.3	0.5	14.7
2030	128.0	9.1	1.7	3.2	4.6	1.8	2.1	0.6	14.0

SO2 EMISSIONS SUMMARY
Contiguous United States - Case B - Limited Life Extension
Retired at Age 60: 50% Peak Demand Growth %: 2.3
SO2 Emissions (Mtons/yr)

	Uncontrolled			Current NSPS			100 % Adv Coal		
Year	Coal Steam	Oil St,CT	Total Fossil	Coal Steam	Oil St,CT	Total Fossil	Coal Steam	Oil St,CT	Total Fossil
1980	23.7	1.4	25.2	15.6	1.4	17.1	15.6	1.4	17.1
1985	29.2	0.8	30.0	15.6	0.8	16.4	15.6	0.8	16.4
1990	31.2	0.6	31.8	15.2	0.6	15.8	15.2	0.6	15.8
1995	37.0	0.8	37.8	15.2	0.8	16.0	15.2	0.8	16.0
2000	45.2	0.8	46.0	15.2	0.8	16.0	14.4	0.8	15.1
2005	56.9	0.7	57.6	15.6	0.7	16.3	14.2	0.7	15.0
2010	68.6	0.7	69.3	15.7	0.7	16.4	13.8	0.7	14.5
2015	84.0	0.6	84.6	15.0	0.6	15.6	12.3	0.6	12.9
2020	99.9	0.5	100.4	14.5	0.5	15.0	11.0	0.5	11.5
2025	113.4	0.4	113.8	14.3	0.4	14.7	10.1	0.4	10.5
2030	127.6	0.4	128.0	13.7	0.4	14.0	8.7	0.4	9.1

PROJECTED SO2 EMISSIONS - NSPS
Contiguous United States - Case B - Limited Life Extension
Retired at Age 60: 55.9% Peak Demand Growth %: 2.3
76.4% SO2 Emissions (Mtons/yr)

	Coal-Steam								
Year	wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	14.9	0.3	0.1	0.0	0.3	15.64	1.4	.0	17.08
1985	14.0	0.9	0.3	0.0	0.3	15.50	0.8	.0	16.43
1990	13.4	1.1	0.4	0.0	0.3	15.23	0.6	.0	15.83
1995	12.9	1.1	0.8	0.0	0.3	15.17	0.8	.0	15.96
2000	12.3	1.1	1.5	0.0	0.3	15.19	0.7	.0	15.96
2005	11.7	1.1	2.5	0.0	0.3	15.58	0.7	.0	16.33
2010	10.0	1.0	3.6	0.0	0.2	15.66	0.7	.0	16.37
2015	8.0	1.0	5.0	0.0	0.2	14.98	0.6	.0	15.59
2020	6.0	0.9	6.6	0.0	0.2	14.47	0.5	.0	14.99
2025	5.7	0.6	7.9	0.0	0.1	14.27	0.4	.0	14.70
2030	3.7	0.6	9.3	0.0	.0	13.68	0.3	.0	14.04

1.0247 1.3233 Calibration Factors
15.64 1.4444

PROJECTED POWER GENERATION
Contiguous United States - Case B - Limited Life Extension
Retired at Age 60: 50% Peak Demand Growth %: 2.3
Power Generation (BkWh/yr)

	Coal-Steam								
Year	wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	916.3	69.4	92.5	0.0	61.2	1139.4	547.5	14.5	1701.5
1985	920.0	190.7	194.5	0.0	67.1	1375.2	352.2	6.0	1733.4
1990	900.7	225.0	268.0	0.0	67.3	1463.9	293.2	8.0	1765.1
1995	882.0	239.6	520.7	0.0	59.7	1702.7	368.3	10.7	2081.7
2000	846.2	231.1	963.6	0.0	61.4	2102.3	257.1	11.8	2371.2
2005	804.0	225.4	1588.1	0.0	51.2	2669.5	221.4	13.1	2904.0
2010	744.7	219.1	2224.1	0.0	43.4	3231.3	165.6	14.5	3411.5
2015	596.3	215.0	3118.9	0.0	29.2	3960.2	99.1	16.2	4075.4
2020	467.3	186.0	4060.4	0.0	20.2	4733.9	76.1	18.0	4828.0
2025	382.5	116.0	4894.1	0.0	10.6	5403.9	58.3	20.0	5482.2
2030	244.0	109.7	5750.0	0.0	4.4	6108.1	48.7	22.3	6179.0

PROJECTED POWER GENERATING CAPACITY
Contiguous United States - Case B - Limited Life Extension
Retired at Age 60: 50% Peak Demand Growth %: 2.3
Generating Capacity (GW)

	Coal-Steam								
Year	wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	187.1	14.9	16.9	0.0	12.0	230.9	153.2	40.2	424.2
1985	186.1	45.5	37.0	0.0	12.0	280.7	145.6	39.3	465.6
1990	184.9	51.9	50.9	0.0	12.0	299.7	139.2	40.9	479.9
1995	175.4	55.3	100.5	0.0	11.6	342.8	123.1	44.9	510.8
2000	169.0	56.6	192.5	0.0	11.6	429.6	110.5	50.0	590.0
2005	163.5	56.6	324.7	0.0	10.2	555.0	96.1	55.6	706.7
2010	153.9	56.6	466.3	0.0	9.0	685.8	74.0	62.0	821.8
2015	125.2	56.6	661.8	0.0	6.3	849.8	48.0	69.2	967.0
2020	99.1	48.0	863.6	0.0	4.6	1016.1	37.5	77.2	1130.9
2025	82.0	30.9	1051.0	0.0	2.5	1166.4	29.5	86.3	1282.2
2030	52.4	29.2	1241.1	0.0	1.0	1323.7	25.0	96.5	1445.2

Table 7

05-Mar-86

PROJECTED SO2 EMISSIONS BY REGION

Contiguous United States - Case C - 100% Life Extension
Retired at Age 60: 100% Peak Demand Growth %: 2.3
SO2 Emissions (Mtons/yr)

Year	Total Uncon-trolled	Total 100 % Adv Coa	NSPS by Region: NE	SE	EC	SC	WC	W	Total NSPS
1980	25.2	17.1	2.3	4.1	5.8	1.6	2.8	0.5	17.1
1985	30.0	16.4	2.2	4.0	5.8	1.6	2.5	0.5	16.4
1990	31.8	15.8	1.7	3.9	5.6	1.7	2.4	0.5	15.8
1995	36.6	16.2	1.8	4.0	5.6	1.9	2.4	0.5	16.2
2000	44.5	15.7	1.9	4.1	5.8	1.8	2.3	0.6	16.5
2005	55.4	15.8	2.0	4.3	5.9	1.8	2.4	0.6	17.1
2010	65.7	15.9	2.0	4.5	6.1	1.9	2.5	0.7	17.6
2015	79.9	15.2	2.0	4.4	5.9	2.0	2.5	0.7	17.5
2020	96.0	14.0	2.0	4.2	5.5	2.2	2.4	0.7	17.1
2025	110.2	12.9	1.9	4.0	5.3	2.4	2.3	0.8	16.8
2030	125.9	10.9	1.7	3.6	5.0	2.4	2.1	0.8	15.6

SO2 EMISSIONS SUMMARY

Contiguous United States - Case C - 100% Life Extension
Retired at Age 60: 100% Peak Demand Growth %: 2.3
SO2 Emissions (Mtons/yr)

	Uncontrolled			Current NSPS			100 % Adv Coal		
Year	Coal Steam	Oil St,CT	Total Fossil	Coal Steam	Oil St,CT	Total Fossil	Coal Steam	Oil St,CT	Total Fossil
1980	23.7	1.4	25.2	15.6	1.4	17.1	15.6	1.4	17.1
1985	29.2	0.8	30.0	15.6	0.8	16.4	15.6	0.8	16.4
1990	31.2	0.6	31.8	15.2	0.6	15.8	15.2	0.6	15.8
1995	35.8	0.8	36.6	15.4	0.8	16.2	15.4	0.8	16.2
2000	43.7	0.8	44.5	15.7	0.8	16.5	15.0	0.8	15.7
2005	54.6	0.8	55.4	16.3	0.8	17.1	15.1	0.8	15.8
2010	65.0	0.7	65.7	16.8	0.7	17.6	15.1	0.7	15.9
2015	79.2	0.7	79.9	16.9	0.7	17.5	14.5	0.7	15.2
2020	95.4	0.6	96.0	16.6	0.6	17.1	13.4	0.6	14.0
2025	109.7	0.5	110.2	16.3	0.5	16.8	12.4	0.5	12.9
2030	125.5	0.4	125.9	15.2	0.4	15.6	10.5	0.4	10.9

PROJECTED SO2 EMISSIONS - NSPS

Contiguous United States - Case C - 100% Life Extension
Retired at Age 60: 100% Peak Demand Growth %: 2.3
SO2 Emissions (Mtons/yr)

	Coal-Steam								
Year	wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	14.9	0.3	0.1	0.0	0.3	15.64	1.4	.0	17.08
1985	14.0	0.9	0.3	0.0	0.3	15.58	0.8	.0	16.43
1990	13.4	1.1	0.4	0.0	0.3	15.23	0.6	.0	15.83
1995	13.2	1.2	0.7	0.0	0.3	15.39	0.8	.0	16.19
2000	12.9	1.1	1.4	0.0	0.3	15.68	0.8	.0	16.47
2005	12.6	1.1	2.3	0.0	0.3	16.28	0.8	.0	17.06
2010	12.3	1.1	3.2	0.0	0.3	16.81	0.7	.0	17.56
2015	11.1	1.1	4.4	0.0	0.3	16.87	0.6	.0	17.53
2020	9.3	1.1	6.0	0.0	0.3	16.56	0.5	.0	17.13
2025	7.8	1.0	7.3	0.0	0.1	16.30	0.4	.0	16.77
2030	5.3	1.0	8.8	0.0	0.1	15.23	0.4	.0	15.63

1.0247 1.3233 Calibration Factors
15.64 1.4444

PROJECTED POWER GENERATION

Contiguous United States Case C - 100% Life Extension
Retired at Age 60: 100% Peak Demand Growth %: 2.3
Power Generation (BkWh/yr)

	Coal-Steam								
Year	wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	916.3	69.4	92.5	0.0	61.2	1139.4	547.5	14.5	1701.5
1985	920.0	198.7	194.5	0.0	62.1	1375.2	352.2	6.0	1733.4
1990	908.7	225.0	268.0	0.0	62.3	1463.9	293.2	8.0	1765.1
1995	907.3	251.7	439.6	0.0	62.4	1660.9	330.1	10.7	2001.7
2000	898.1	240.4	837.2	0.0	65.9	2041.6	317.8	11.8	2371.2
2005	874.6	235.6	1406.0	0.0	62.5	2578.7	312.2	13.1	2904.0
2010	849.6	231.4	1954.6	0.0	60.0	3095.6	301.3	14.5	3411.5
2015	763.6	228.0	2743.4	0.0	56.2	3791.2	268.0	16.2	4075.4
2020	635.9	225.3	3669.1	0.0	53.0	4583.3	226.0	18.8	4828.0
2025	529.8	221.8	4496.7	0.0	35.6	5283.9	178.3	20.0	5482.2
2030	351.6	218.4	5445.8	0.0	23.0	6038.7	118.1	22.3	6179.0

PROJECTED POWER GENERATING CAPACITY

Contiguous United States - Case C - 100% Life Extension
Retired at Age 60: 100% Peak Demand Growth %: 2.3
Generating Capacity (GW)

	Coal-Steam								
Year	wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	187.1	14.9	16.9	0.0	12.0	230.9	153.2	40.2	424.2
1985	186.1	45.5	37.0	0.0	12.0	280.7	145.6	39.3	465.6
1990	184.9	51.9	50.9	0.0	12.0	299.7	139.2	40.9	479.9
1995	178.3	55.3	81.4	0.0	11.7	326.7	139.2	44.9	510.8
2000	176.8	56.6	160.9	0.0	11.7	405.9	134.1	50.0	590.0
2005	175.0	56.6	276.5	0.0	11.7	519.7	131.4	55.6	706.7
2010	173.1	56.6	392.5	0.0	11.7	633.8	126.0	62.0	821.8
2015	157.7	56.6	560.1	0.0	11.2	785.5	112.3	69.2	967.0
2020	132.8	56.5	758.9	0.0	10.8	958.9	94.7	77.2	1130.9
2025	111.9	56.4	945.4	0.0	7.3	1121.0	74.9	86.3	1282.2
2030	74.5	56.4	1161.8	0.0	4.7	1297.3	51.4	96.5	1445.2

Table 8

05-Mar-86 PROJECTED SO2 EMISSIONS BY REGION
Contiguous United States - Case B - 100% Life Extension
Retired at Age 60: 100% Peak Demand Growth %: 3.3
SO2 Emissions (Mtons/yr)

Year	Total Uncon-trolled	Total 100 % Adv Coa	NSPS by Region: NE	SE	EC	SC	WC	W	Total NSPS
1980	25.2	17.1	2.3	4.1	5.8	1.6	2.8	0.5	17.1
1985	30.0	16.4	2.2	4.0	5.8	1.6	2.5	0.5	16.4
1990	31.8	15.8	1.7	3.9	5.6	1.7	2.4	0.5	15.8
1995	37.2	16.2	1.8	4.0	5.6	1.9	2.4	0.5	16.2
2000	48.6	15.7	1.9	4.1	5.9	1.8	2.3	0.6	16.6
2005	64.1	15.9	2.0	4.4	6.1	1.9	2.5	0.7	17.5
2010	80.3	16.2	2.1	4.7	6.3	2.0	2.6	0.7	18.5
2015	101.7	15.8	2.2	4.7	6.3	2.3	2.7	0.8	19.1
2020	127.1	14.9	2.3	4.7	6.1	2.6	2.7	0.9	19.4
2025	152.7	14.3	2.4	4.7	6.2	2.9	2.7	1.0	20.0
2030	182.5	12.9	2.4	4.6	6.2	3.1	2.7	1.1	20.0

SO2 EMISSIONS SUMMARY
Contiguous United States - Case B - 100% Life Extension
Retired at Age 60: 100% Peak Demand Growth %: 3.3
SO2 Emissions (Mtons/yr)

Year	Uncontrolled Coal Steam	Oil St,CT	Total Fossil	Current NSPS Coal Steam	Oil St,CT	Total Fossil	100 % Adv Coal Coal Steam	Oil St,CT	Total Fossil
1980	23.7	1.4	25.2	15.6	1.4	17.1	15.6	1.4	17.1
1985	29.2	0.8	30.0	15.6	0.8	16.4	15.6	0.8	16.4
1990	31.2	0.6	31.8	15.2	0.6	15.8	15.2	0.6	15.8
1995	36.4	0.8	37.2	15.4	0.8	16.2	15.4	0.8	16.2
2000	47.9	0.8	48.6	15.8	0.8	16.6	14.9	0.8	15.7
2005	63.3	0.8	64.1	16.8	0.8	17.5	15.2	0.8	15.9
2010	79.5	0.8	80.3	17.7	0.8	18.5	15.4	0.8	16.2
2015	101.1	0.7	101.7	18.4	0.7	19.1	15.1	0.7	15.8
2020	126.5	0.6	127.1	18.8	0.6	19.4	14.3	0.6	14.9
2025	152.2	0.5	152.7	19.5	0.5	20.0	13.8	0.5	14.3
2030	182.1	0.4	182.5	19.6	0.4	20.0	12.5	0.4	12.9

PROJECTED SO2 EMISSIONS - NSPS
Contiguous United States - Case B - 100% Life Extension
Retired at Age 60: 100% Peak Demand Growth %: 3.3
SO2 Emissions (Mtons/yr)

Year	Coal-Steam wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	14.9	0.3	0.1	0.0	0.3	15.64	1.4	.0	17.00
1985	14.0	0.9	0.3	0.0	0.3	15.58	0.8	.0	16.43
1990	13.4	1.1	0.4	0.0	0.3	15.23	0.6	.0	15.83
1995	13.1	1.2	0.8	0.0	0.3	15.39	0.8	.0	16.28
2000	12.7	1.1	1.7	0.0	0.3	15.83	0.8	.0	16.62
2005	12.4	1.1	3.0	0.0	0.3	16.75	0.8	.0	17.53
2010	12.0	1.1	4.4	0.0	0.3	17.74	0.7	.0	18.49
2015	10.8	1.0	6.2	0.0	0.3	18.38	0.6	.0	19.05
2020	9.1	1.0	8.5	0.0	0.3	18.82	0.5	.0	19.40
2025	7.7	1.0	10.7	0.0	0.1	19.49	0.4	.0	19.97
2030	5.2	1.0	13.3	0.0	0.1	19.58	0.4	0.1	19.99

1.0247 1.3233 Calibration Factors
15.64 1.4444

PROJECTED POWER GENERATION
Contiguous United States - Case B - 100% Life Extension
Retired at Age 60: 100% Peak Demand Growth %: 3.3
Power Generation (BkWh/yr)

Year	Coal-Steam wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	916.3	69.4	92.5	0.0	61.2	1139.4	547.5	14.5	1701.5
1985	920.0	198.7	194.5	0.0	62.1	1375.2	352.2	6.0	1733.4
1990	908.7	225.0	268.0	0.0	62.3	1463.9	293.2	8.0	1765.1
1995	909.0	250.9	468.1	0.0	62.3	1690.3	330.1	10.8	2031.2
2000	884.4	235.7	1059.2	0.0	63.9	2243.2	317.8	12.5	2573.4
2005	858.5	229.4	1853.7	0.0	60.4	3002.0	312.2	14.6	3328.8
2010	833.3	224.5	2685.7	0.0	58.1	3801.5	301.3	17.0	4119.8
2015	749.3	221.1	3829.4	0.0	54.6	4854.4	268.0	19.8	5142.3
2020	624.2	218.4	5200.6	0.0	51.9	6095.1	226.8	23.2	6345.0
2025	521.0	215.1	6584.7	0.0	35.0	7355.7	178.3	27.1	7561.1
2030	346.5	212.3	8224.9	0.0	22.7	8806.4	118.1	31.7	8956.1

PROJECTED POWER GENERATING CAPACITY
Contiguous United States - Case B - 100% Life Extension
Retired at Age 60: 100% Peak Demand Growth %: 3.3
Generating Capacity (GW)

Year	Coal-Steam wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	187.1	14.9	16.9	0.0	12.0	230.9	153.2	40.2	424.2
1985	186.1	45.5	37.0	0.0	12.0	280.7	145.6	39.3	465.6
1990	184.9	51.9	50.9	0.0	12.0	299.7	139.2	40.9	479.9
1995	178.3	55.3	87.2	0.0	11.7	332.4	139.2	45.3	516.9
2000	176.8	56.6	206.5	0.0	11.7	451.5	134.1	53.0	638.6
2005	175.0	56.6	372.2	0.0	11.7	615.5	131.4	61.9	808.8
2010	173.1	56.6	552.2	0.0	11.7	793.5	126.0	72.5	991.9
2015	157.7	56.6	800.5	0.0	11.2	1026.0	112.3	84.9	1223.1
2020	132.8	56.5	1100.6	0.0	10.8	1300.7	94.7	99.5	1494.8
2025	111.9	56.4	1413.6	0.0	7.3	1589.2	74.9	116.7	1780.7
2030	74.5	56.4	1787.0	0.0	4.7	1922.6	51.4	137.0	2110.9

Table 9

05 Mar-86 PROJECTED SO2 EMISSIONS BY REGION
Contiguous United States - CRS Case
Retired at Age 60: 100% Peak Demand Growth %: 3.1
SO2 Emissions (Mtons/yr)

Year	Total Uncon-trolled	Total 100 % Adv Coa	NSPS by Region: NE	SE	EC	SC	WC	W	Total NSPS
1980	26.3	18.0	2.4	4.4	4.7	2.5	2.4	1.6	18.0
1985	29.7	17.7	2.3	4.3	4.8	2.4	2.3	1.5	17.7
1990	31.1	16.5	1.8	4.3	4.4	2.4	2.1	1.5	16.5
1995	35.8	16.8	1.9	4.4	4.4	2.7	2.0	1.5	16.8
2000	46.2	16.4	1.9	4.5	4.6	2.6	2.0	1.7	17.2
2005	60.6	16.6	2.0	4.8	4.7	2.7	2.2	1.8	18.1
2010	75.4	16.7	2.1	5.0	4.8	2.8	2.3	1.9	18.9
2015	94.8	16.2	2.2	5.0	4.6	3.0	2.4	2.1	19.3
2020	117.4	15.1	2.3	4.9	4.3	3.2	2.4	2.2	19.3
2025	139.7	14.3	2.3	4.8	4.3	3.3	2.4	2.4	19.5
2030	165.0	12.5	2.2	4.5	4.0	3.4	2.3	2.6	19.1

SO2 EMISSIONS SUMMARY
Contiguous United States CRS Case
Retired at Age 60: 100% Peak Demand Growth %: 3.1
SO2 Emissions (Mtons/yr)

	Uncontrolled			Current NSPS			100 % Adv Coal		
Year	Coal Steam	Oil St,CT	Total Fossil	Coal Steam	Oil St,CT	Total Fossil	Coal Steam	Oil St,CT	Total Fossil
1980	22.7	3.6	26.3	14.3	3.6	18.0	14.3	3.6	18.0
1985	27.4	2.3	29.7	15.3	2.3	17.7	15.3	2.3	17.7
1990	29.1	1.9	31.1	14.6	1.9	16.5	14.6	1.9	16.5
1995	33.6	2.2	35.8	14.6	2.2	16.8	14.6	2.2	16.8
2000	44.1	2.1	46.2	15.1	2.1	17.2	14.3	2.1	16.4
2005	58.5	2.1	60.6	16.0	2.1	18.1	14.5	2.1	16.6
2010	73.4	2.0	75.4	16.9	2.0	18.9	14.7	2.0	16.7
2015	93.0	1.8	94.8	17.5	1.8	19.3	14.4	1.8	16.2
2020	115.9	1.5	117.4	17.8	1.5	19.3	13.6	1.5	15.1
2025	138.5	1.2	139.7	18.3	1.2	19.5	13.1	1.2	14.3
2030	164.1	0.8	165.0	18.2	0.8	19.1	11.7	0.8	12.5

PROJECTED SO2 EMISSIONS NSPS
Contiguous United States - CRS Case
Retired at Age 60: 100% Peak Demand Growth %: 3.1
SO2 Emissions (Mtons/yr)

	Coal-Steam								
Year	wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	13.6	0.5	0.1	0.0	0.1	14.34	3.6	.0	17.95
1985	13.5	1.5	0.3	0.0	0.1	15.34	2.3	.0	17.64
1990	12.4	1.7	0.4	0.0	0.1	14.57	1.9	.0	16.51
1995	12.0	1.9	0.7	0.0	0.1	14.60	2.2	.0	16.79
2000	11.7	1.8	1.5	0.0	0.1	15.14	2.1	.0	17.25
2005	11.5	1.8	2.7	0.0	0.1	16.02	2.0	.0	18.10
2010	11.2	1.7	3.9	0.0	0.1	16.91	2.0	.0	18.92
2015	10.1	1.7	5.5	0.0	0.1	17.47	1.8	.0	19.26
2020	8.5	1.7	7.5	0.0	0.1	17.77	1.5	.0	19.29
2025	7.1	1.7	9.4	0.0	0.1	18.31	1.2	.0	19.53
2030	4.8	1.7	11.7	0.0	.0	18.23	0.8	0.1	19.06

1.0247 1.3233 Calibration Factors
15.64 1.4444

PROJECTED POWER GENERATION
Contiguous United States - CRS Case
Retired at Age 60: 100% Peak Demand Growth %: 3.1
Power Generation (BkWh/yr)

	Coal-Steam								
Year	wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	910.6	76.5	89.6	0.0	62.7	1139.4	547.5	14.5	1701.5
1985	904.0	270.9	137.4	0.0	63.0	1375.2	352.2	6.0	1733.4
1990	889.3	253.1	258.5	0.0	63.1	1463.9	293.2	8.0	1765.1
1995	894.6	283.6	444.8	0.0	63.3	1686.4	330.1	10.8	2027.3
2000	873.8	270.6	1005.7	0.0	64.6	2214.6	317.8	12.5	2544.9
2005	854.6	266.4	1755.8	0.0	61.2	2938.0	312.2	14.6	3264.8
2010	832.8	262.2	2533.7	0.0	59.1	3687.8	301.3	17.0	4006.1
2015	752.7	259.9	3604.4	0.0	55.3	4672.3	268.0	19.8	4960.1
2020	629.4	257.9	4880.8	0.0	52.3	5820.4	226.8	23.0	6070.2
2025	525.7	254.7	6142.0	0.0	34.9	6957.3	178.3	26.8	7162.4
2030	348.9	252.2	7621.0	0.0	22.0	8244.0	118.1	31.2	8393.4

PROJECTED POWER GENERATING CAPACITY
Contiguous United States - CRS Case
Retired at Age 60: 100% Peak Demand Growth %: 3.1
Generating Capacity (GW)

	Coal-Steam								
Year	wo FGD	71NSPS wo FGD	with FGD	Advd Coal	Retro FGD	Total Coal	Oil Steam	Oil CT	Total Fossil
1980	187.1	14.9	16.9	0.0	12.0	230.9	153.2	40.2	424.2
1985	186.1	45.5	37.0	0.0	12.0	280.7	145.6	39.3	465.6
1990	184.9	51.9	50.9	0.0	12.0	299.7	139.2	40.9	479.9
1995	178.3	55.3	85.7	0.0	11.7	330.9	139.2	45.3	515.4
2000	176.8	56.6	200.5	0.0	11.7	445.5	134.1	52.8	632.4
2005	175.0	56.6	358.6	0.0	11.7	601.8	131.4	61.5	794.7
2010	173.1	56.6	527.8	0.0	11.7	769.1	126.0	71.7	966.8
2015	157.7	56.6	761.4	0.0	11.7	986.8	112.3	83.5	1182.6
2020	132.8	56.5	1041.4	0.0	10.8	1241.4	94.7	97.2	1433.4
2025	111.9	56.4	1327.4	0.0	7.3	1503.0	74.9	113.3	1691.2
2030	74.5	56.4	1665.1	0.0	4.7	1800.7	51.4	132.0	1984.0

APPENDIX A

POWER PLANT REFURBISHMENT

Motivating Factors Maintaining the operation of power plants at high availability beyond their normal service life is one of a set of strategic options being considered by many utilities for meeting future load demand projections. When combined with a balanced contribution from new generation, end-use management, purchased power and conservation, etc. plant refurbishment should help provide an effective means of meeting load demands in the 1990s for a number of utilities.

U.S. electric utilities operate over 1500 fossil fired units with an installed capacity of over 440 GW(e). Because of plant cancellations and the lack of plant orders resulting from the high cost of money, high capital equipment costs, reduced and uncertain load demand, fuel price uncertainty, facility siting requirements and environmental regulations, the average age of these fossil plants will increase substantially in the future. By 1995, if present ordering patterns continue, fossil fired plants will have aged to a point where over 25% of coal fired capacity and 50% of oil and gas fired capacity will be over 30 years old. New unit construction costs now range from 1200$/kW to 2000$/kW. In contrast, extending the life of existing units for an additional 10 to 25 years by refurbishment may be achievable for 150-300$/kW coupled with more intensive diagnostic and planned maintenance efforts during the extended life period. These costs may be economically justified if the desired availability can be confidently maintained for the additional 10 to 25 year target.

In addition, these candidates for extended refurbishment have attractive unit sizes (50-300MW) and competitive heat rates. As a result, many utilities are adopting this strategy as part of their long-range generation expansion plan. The decision to perform extended refurbishment is based mostly on economics and is utility specific. Some of the factors involved include reserve margins, load growth projections, financial condition, fuel mix and age mix. Depending upon the combination of factors within a given utility, life extension may or may not be an attractive option. Therefore, not all aging capacity is expected to be life extended even if it is technically feasible to do so. Detailed systems feasibility studies will be required to make these decisions based on the widely varying condition of the candidate units. For example, between now and the end of the century about 55,000 MW of coal-fired (Table 1) and 40,000 MW of oil/gas capacity will exceed 40 years of age and become life extension candidates. This constitutes over 15% of the nation's generating capacity today.

TABLE 1

POPULATION OF COAL-FIRED UNITS
WHICH WILL EXCEED 40 YEARS IN AGE BY 2000

SIZE	TOTAL CAPACITY	NUMBER
<75	9800	346
75-150	19300	175
150-300	22800	117
300-600	2600	8
	54,500	646

Approach Fossil generating units have traditionally been built with an assumed life of 30-40 years. These units have been operating at high levels of availability and performance with planned maintenance programs. However, as units age beyond their normal lifetime, degradation mechanisms such as creep, fatigue, corrosion and erosion may render critical components (boiler drums, turbine rotors) incapable of performing their intended service in the unit. As a result, these aging mechanisms may cause significant reductions in plant availability and performance. Refurbishment is intended to counteract the degradation of unit performance and allow a utility to make sound rehabilitation decisions to ensure continued safe and economic operation of his total system.

The overall objective of an extended refurbishment program, therefore, is to implement a strategy for maintaining generating units in service as long as economically practical while achieving targeted levels of availability, performance and production costs. This involves a top-down process including corporate, financial and system planning;

detailed plant inspection and component evaluations; determination of upgrade options; production cost analysis and implementation into the utility system.

Two basic approaches are being implemented by utilities: (1) identifying several specific aging units on the system for major refurbishment, (2) refurbishing all units on a system in a phased manner over the life of the system. The approach adopted by a specific utility depends heavily on its individual needs and longe range generation plan.

Uncertainties As can be seen from the foregoing discussion, the decision to implement extended refurbishment involves a complex process of corporate planning, plant evaluation and implementation. Also, life extension is a relatively recent addition to generation expansion planning for electric utilities. As a result, a wide variety of economic, technical and regulatory uncertainties exist regarding the viability and ultimate implementation of the life extension option by the utility industry.

Of major importance is the life-cycle cost of extended refurbishment. Initial utility efforts place the capital cost at between \$150/kW and \$300/kW. However, very little experience has been gained with extended refurbishment and, potentially, a number of unforeseen problems may surface that could drive both capital and inspection/maintenance costs higher. In addition, it may be necessary to consider additional emission control requirements. For example, if reconstruction costs exceed 50% of the replacement cost of a new steam generator, the unit might be required to meet New Source Performance Standards (NSPS). If a flue gas scrubbing system is installed this will typically add \$250/kW to the cost of life extension. The likelihood of this requirement can be judged by the fact that the installed cost of a new 200 MW boiler is typically about \$40 million (\$200/kW).

Figures A and B indicate how the economic attractiveness of the refurbishment option is rendered more uncertain as cost increases and is particularly affected by the capacity factor for the refurbished unit.

Very little historical information is available regarding the reliability of units when operated beyond their design life. Information from the NERC-GADS data base indicates that forced outages of units greater than 20 years old is 4 to 5 times higher than when the unit is at its prime, often reaching 20% or more. Also, the direct cause and effect relationship between unit availability and declining component reliability with age is not well known. Similarly, uncertainties exist regarding the effect of age on thermal efficiency, power output, and operation and maintenance costs. Consequently, substantial risk remains that unit implementation approaches may not achieve system performance goals.

Considering the foregoing uncertainties and emission control costs, it is increasingly probable that the approach will only be applied selectively. In many cases it may be more cost effective to convert or replace the existing boiler with a fluidized bed combustion (FBC) unit, for example. This would reduce fuel and environmental control costs, eliminate scrubbers and more confidently maintain availability.

Prospects

Since extended refurbishment is a relatively new and untried means of helping utilities meet future load demand projections as such, it is extremely difficult to predict the extent to which it will be applied. For a number of utilities with the right combination of system characteristics, the economics will almost certainly be in favor of the extended refurbishment option and they will apply the approach to units on their system. Conversely, for many other utilities, life extension will not be a viable option. Indeed a large percentage of these utilities may retire the older units on their system in the normal manner.

In any case, the majority of utilities will be required to make difficult economic decisions regarding the use of extended refurbishment taking into account the major economic, technical and regulatory uncertainties discussed earlier. Over the next 5 to 10 years most utilities will perform detailed technical and economic feasibility studies to evaluate the extended refurbishment option. It is difficult to speculate on the outcome of these studies but the following trends are emerging:

- Substantial engineeering and development efforts are being expended by utilities and suppliers to reduce the risks in extended refurbishment.

- Most units less than 50 MW will probably will not be refurbished.

- The planned period of unit life extension typically ranges from 10 to 25 years.

- Utilities with low reserve margins, and average or higher load growth may be more likely to opt for extended refurbishment.
- Refurbishment could trigger the need to meet more stringent emission control requirements, either under local or national regulation.

Based on these considerations, the explicit assumption that all utilities will adopt extended refurbishment and that all old plants will be refurbished is not reasonable. The exact percentage cannot be explicitly defined but is unlikely to exceed 75% of the candidate units and, in many cases, will depend on replacement of the existing boiler with a more cost effective alternative such FBC.

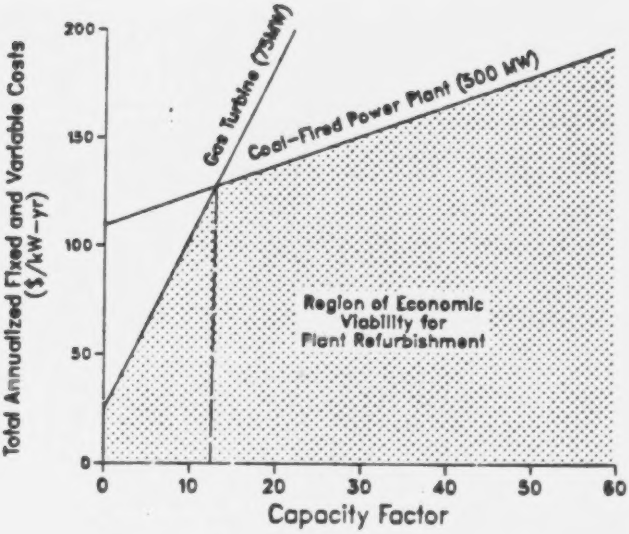

FIGURE A. Screening Curves Comparing Fixed and Variable Cost Characteristics for Illustrative Example

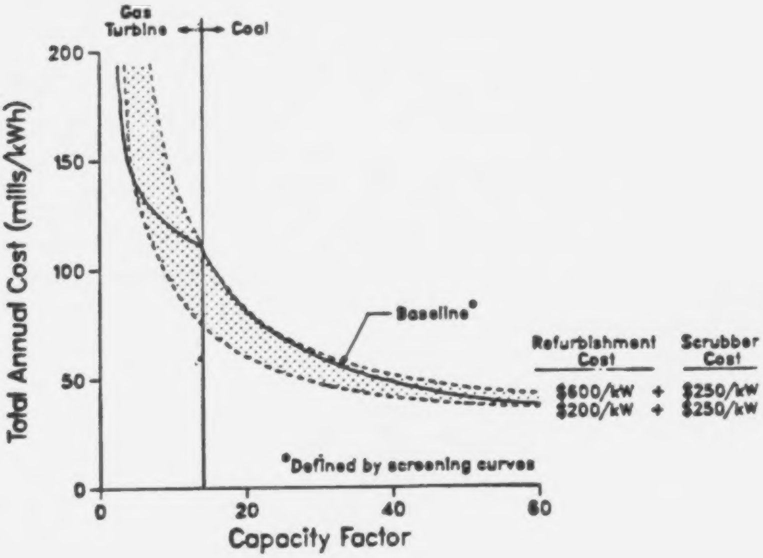

FIGURE B. Comparison of Refurbishment and New Capacity Costs Assuming an FGD System is Required for the Refurbished Unit

Summary of Key Assumptions for Illustrative Levelized-Cost Comparison[a]

Unit	Parameter	Value
Gas Turbine (75MWe):	Capital Cost ($/kW)	215
	Fixed O&M ($/kW-yr)	0.4
	Variable O&M (mills/kWh)	3.2
	Fuel Cost ($/$10^6$ Btu)	6.8
	Heat Rate (Btu/kWh)	13,800
Coal Replacement Unit (500MWe):	Capital Cost ($/kW)[b]	995
	Fixed O&M ($/kW-yr)	14.2
	Variable O&M (mills/kWh)	3.3
	Fuel Cost ($/$10^6$ Btu)	1.65
	Heat Rate (Btu/kWh)	10,040
Refurbished Coal Unit (500 MWe):[c]	Capital Cost of Refurbishment ($/kW)	200-600
	Capital Cost for Scrubbers ($/kW)	250
	Fixed O&M costs	
	- without scrubbers ($/kW-yr)	8.5
	- with scrubbers ($/kW-yr)	17.04
	Variable O&M costs	
	- without scrubbers (mills/kWh)	1.1
	- with scrubbers (mills/kWh)	3.3
	Fuel Cost ($/$10^6$ Btu)	1.65
	Heat Rate (Btu/kWh)	10,743

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[a] The assumed fixed charge rate is 10%. Real escalation is zero for all component costs.

[b] Includes the cost of scrubbers.

[c] A one year outage is assumed for refurbishment. Replacement power is costed at $40/MWh.

APPENDIX B

Emission Reduction Analysis Model (ERAM) Data Base

The ERAM project was started in 1980. ERAM is a research computer model (operated on an IBM-PC) designed to assess the value of EPRI R&D and the applicability of alternative technologies for the control of SO_2, NO_x, and particulates from fossil fuel-fired steam boilers. To support the model, a generating unit-specific data base was developed using several sources including the Utility Data Institute (UDI), Environmental Protection Agency (EPA), North American Electric Reliability Council (NERC), National Coal Association (NCA), and EPRI contractors (KVB, Stearns-Catalytic, TERA Corporation). Table B-1 lists specific references used in compiling the data base. To date, approximately three man years of effort has been required to compile the information, write software, verify data, fill data gaps, and keep the information up-to-date. This effort has resulted in a high quality data base which is used for internal EPRI R&D planning studies.

The data base contains specific information on each fossil fuel-fired steam generating unit in the U.S. over 25 MW plus numerous other data files to run the ERAM code. Examples of the data items include:

a. General unit data (size, generation, on-line year, heat rate, fuel type, etc.).

b. Emissions (historical emissions, control efficiencies, future baseline emissions limits, averaging times).

c. Emissions controls (historical and known future devices, operating dates.)

d. Fuels (characteristics of historical, future baseline, and unit-specific future alternative fuels).

e. Retrofit factors and applicabilities for each control technology.

f. Regional constraint data (files grouping units into regions, regional emissions and cost constraints).

For this study the ERAM data base was used for the tasks noted below.

(1) To determine the total fossil fuel steam generating capacity, retirements, new caspacity, and coal conversions to the year 1994 based on NERC data. These data were used to verify and correct the EPRI capacity planning model which projects new capacity and retirements out to year 2030.

(2) To determine the capacity, generation, and SO_2 emissions for the following four emission control categories for historical years 1980-1990:

> (a) pre NSPS units without FGD, (b) 1971 NSPS units without FGD, (c) all units with retrofit FGD, and (d) all units required by regulation to have FGD at the time they commence operation.

(3) To derive historical unit capacity factors, heat rates and coal heating values and sulfur content for each NERC region. Unit data were aggregated by age and applicable SO_2 control technology and used to provide a consistent basis for calculating SO_2 emissions.

(4) To identify life extension candidates based on unit size and age in each NERC region.

Table B-1

DATA SOURCES FOR EPRI EMISSIONS REDUCTION ANALYSIS MODEL (ERAM)

Specific Power Plant Data	Source
o Location by State	1
o Installed Capacity	2
o Installation Date	3
o FGD	4
o Net Heat Rate	5
o Capacity Factor	6
o Coal Sulfur and Heat Contents	7

1. Power Directory, Edison Electric Institute, 1983, 1984.
2. a. Regional Reliability Council Long Range Coordinated Bulk Power Supply Programs, Northeast Power Coordinating Council, April 1, 1985, (IE-411).
   b. MAAC Regional Reliability Council Coordinated Bulk Power Supply Program, Mid-Atlantic Area Council, April 1, 1985, (IE-411).
   c. ECAR Coordinated Regional Bulk Power Supply Program, East Central Area Reliability Coordination Agreement, April 1, 1985, (IE-411).
   d. MAIN Regional Reliability Council Coordinated Bulk Power Supply Program, Mid-America Interpool Network, April 1, 1985, (IE-411).
   e. MAPP Coordinated Bulk Power Supply Program, Mid-Continent Area Power Pool, April 1, 1985, (IE-411).
   f. Southeastern Electric Reliability Council Coordinated Bulk Power Supply Program, Southeastern Electric Reliability Council, April 1, 1985, (IE-411).
   g. Regional Reliability Council Coordinated Bulk Power Supply Program, Southwest Power Pool, April 1, 1985, (IE-411).
   h. Report by Electric Reliability Council of Texas to the U.S. Department of Energy Coordinated Bulk Power Supply Program under IE-411, Electric Reliability Council of Texas, April 1, 1985, (IE-411).
   i. Coordinated Bulk Power Supply Program 1984-1994, Western Systems Coordinating Council, April 1, 1985, (IE-411).

Table B-1 continued

3. See 1 and 2 above.
4. Utility FGD Systems, Edison Electric Institute, May, 1984.
5. a. TERA Corporation, Proprietary Data, 1980 information.
    b. KVB, Inc., Proprietary Data, 1980 information.
    c. Utility Data Institute, Edison Electric Institute Power Statistics, 1983 information.
6. See 5 above; in addition:
    d. Steam Electric Plant Factors, National Coal Association, 1981.
    e. Thermal-Electric Plant Construction Cost and Annual Production Expenses, 1980. U.S. Energy Information Administration, 1981.
7. a. Utility Data Institute, Edison Electric Institute Power Statistics, 1983 information.
    b. Steam Electric Plant Factors, National Coal Association, 1981-1984.

ATTACHMENT B

EMERGING CLEAN COAL TECHNOLOGIES

An enhanced Clean Coal research, development and demonstration program represents an important need because of the nation's limited ability to develop and apply superior clean coal technology. The present lack of adequate funding mechanisms to demonstrate the reliability, economics and performance of new coal technology is a source of national concern. While private sector efforts have been maintained, they are insufficient in the face of declining incentives for additional private investment. As a result, there is a number of key coal based technologies where the funding to achieve prompt development and demonstration is not evident. This may have profound consequences for the 1990s when new electric generating demands, which must rely on coal, collide with the growing environmental ethic of our society. Emerging clean coal technologies that can benefit by an accelerated Federal and private sector effort are described below.

A. Control Technology

1. Coal Preparation

Coal quality improvement and control is central to the efficient, reliable, and environmentally acceptable performance of coal-fired utility power plants. Coal quality improvement technology will also be a critical factor in realizing the economic benefits of many advanced, coal-based energy conversion technologies, such as coal gasification and fuel cells. Many advanced energy conversion processes are more sensitive to coal quality and variability than current technologies. For these processes, the economic trade-offs between the cost of coal upgrading and process capital and operating cost savings strongly favor appreciable levels of coal cleaning.

Recently, coal cleaning--largely using technology developed in the late 1940s--has become increasingly important to the electric utility industry in their efforts to reduce electricity cost. This technology, which requires low capital expenditure compared with generating plants is being increasingly applied to remove sulfur and ash, reduce coal heating value variability, and improve combustion characteristics. Statistics recently released by the Department of Energy for 1983 indicate that nearly 70% of the coal burned by utilities east of the Mississippi was physically cleaned.

This represents a large increase from 1978, the last year before 1983 that such statistics were collected, when only 45% of eastern steam coal was cleaned. Coal cleaning is clearly a major response of the utility industry to environmental regulations and can reduce fuel cost through increased coal purchasing flexibility. Priority objectives for research and development to improve coal quality and quality monitoring and control include:

- Improved sampling and analytical procedures to insure confidence in quantity and quality estimates from in-situ reserves for power station coal feed.
- Techniques for improving the slagging and fouling characteristics of lower rank, Western coals.
- More efficient and economic physical fine coal cleaning and dewatering technology.
- More economic chemical cleaning techniques providing for high levels of sulfur and ash removal.
- Automated cleaning process control and on-line continuous measurement techniques to improve reliability and product quality.

To support the electric utility industry's need to improve coal quality, improve cleaning processes energy recovery, and reduce cleaning cost, EPRI has operated for the past three years a unique coal cleaning R&D facility; the EPRI Coal Cleaning Test Facility (CCTF). Major goals of this 20 ton per hour test facility are to:

- Characterize the cleanability of U.S. steam coals.
- Develop and demonstrate new and improved coal cleaning technology.
- Develop a national coal quality data base to improve commercial coal cleaning plant design and operations.
- Develop and demonstrate new coal cleaning process instrumentation and control systems.
- Provide practical training for coal cleaning engineers.

A major project initiated at the CCTF in 1985 is a joint Department of Energy and EPRI effort to test advanced physical coal cleaning processes. Under this project, two novel high performance advanced processes will be tested. Process test modules will be operated at approximately one ton per hour, and will test a wide range of U.S. coals. The Department of Energy will perform combustion tests both on the raw coals feeding the processes and the product coals to evaluate the changes in combustion characteristics, and in the nature of the ashes produced by combustion.

Two processes have been selected for testing under this joint advanced physical coal clean ng assessment project. This selection is in response to a DOE solicitation. These are a micro-bubble flotation process (contractor: Bechtel Group, Inc.) and a dry electrostatic cleaning prs (contractor: Advanced Energy Dynamics). Agreements were signed with the two contractors by the Department of Energy in September, 1985. EPRI is currently initiating engineering of the modifications to the CCTF to receive the process test modules, provide them with services, feed them with coal, and remove the product and refuse.

Additional cooperative R&D, to better match limited resources with the potential energy cost savings, is desirable between EPRI and DOE and also with the coal industry, an industry which traditionally has not supported R&D. To date the U.S. coal industry has not become a force in coal quality research and development. This absence is a great weakness when it comes to transferring technology, because it will predominantly be up to the coal industry to use coal cleaning advances. There is a limited and largely informal use of industry experts on advisory committees by EPRI and DOE. However, for a great improvement in new clean coal technology a mechanism for increasing R&D support in the coal industry for clean coal and general coal quality work should be found. The demands of environmental protection offer an excellent opportunity to the coal industry to add value to their product and increase their profitability. It would be unforunate if their short-term cash flow weaknesses removed the opportunity.

2. Flue Gas Cleanup

   a. Flue Gas Desulfurization (FGD)

The highest priority should be placed on resolving the reliability, by-product disposal and cost issues impeding the effectiveness of Flue Gas Desulfurization (FGD) for use on high sulfur coal retrofits.

Federal participation is especially encouraged at the High Sulfur Test Center currently under construction in Western New York State. This center will help resolve chemistry, reliability and materials problems with existing FGD systems and reduce the cost and reliability impact of potential retrofit scrubbers. This industry initiative now has funding of $20 million for construction and over $20 million for operation from EPRI, New York State Electric & Gas, New York State Energy Research & Development Authority and Empire State Electric Energy Research Corporation. Additional funding from U.S. and foreign utilities, coal companies, and other sources is now being solicited. Modest federal funding could be structured in a manner similar to the successful EPRI/DOE advanced coal cleaning development project at the EPRI Coal Cleaning Test Facility.

Simplified and improved FGD processes developed by the private sector, such as the Chiyoda 121 Process, also deserve DOE support. These processes will likely be proposed as part of the clean coal technology solicitation process. This support should not be limited to processes that are 90% efficient. DOE has contracted for development of low-cost retrofit technology with lower removal efficiency in the last year, and this effort should be expanded where there is a matching industry initiative.

A final area of flue gas cleaning requiring additional Federal attention is particulate control technology improvement. All of the technologies to reduce SO_2 emissions from coal cleaning to scrubbers, will have a major impact on the quantity and quality of particulate matter to be collected. Present electrostatic precipitator technology lacks the flexibility to adapt to these new conditions without substantial losses in collection efficiency unless an intensive development and testing effort is initiated.

Demonstration of a combined SO_x/NO_x removal system within the next five years is speculative. Although DOE is today supporting development of several such technologies including the Sulf-X and E-Beam processes, these are still at relatively small scale and a preliminary stage of development. They are unlikely to achieve sufficient performance or cost confidence within the near future to justify large prototype facilities. Increased funding for smaller pilot scale development would probably be more effective within this time frame.

b. Low NO_x Combustion Systems

This too is an area of importance where DOE is not currently involved, at least not beyond fundamental research into the chemistry and physics of NO_x formation. Although DOE is exploring flue gas cleaning systems that reduce this pollutant, the NO_x issue requires accelerated attention in the near term by the development of modified burners that can reduce NO_x substantially (i.e., 50-75%). Such techniques offer the lowest cost approach to reduce NO_x emissions, as well as acid rain precursors if NO_x credits are allowed. While it appears that many coal-fired utility boilers could be retrofitted with low NO_x burners, the different flame shape and specific geometric and mechanical requirements of these new systems can represent significant changes for existing equipment. In addition to these boiler engineering issues, the potential operational and reliability impact of low NO_x burners retrofits must also be addressed through large demonstration tests.

Low NO_x burners are designed specifically for a given boiler type, and commercial scale units for the two boiler types (wall- and tangential-fired) representing the largest installed capacities in the United States are ready for field demonstration. Other boiler types have a significant impact on emissions due to their uncontrolled NO_x emission rates. EPRI is working with vendors to develop low NO_x combustion modification systems for two of these types (units with cell burners and cyclones). An improved cell burner is now ready for field testing, and a lower NO_x cyclone system may be demonstrated at the pilot-scale by 1988, at which time it should be subjected to field trials.

To prepare the utility industry in the event of retrofit NO_x requirements, EPRI is working with utilities and vendors to plan low-NO_x burner field demonstrations for each major boiler type. Although we are discussing a jointly sponsored field demonstration with EPA, that project would address just one burner/boiler type. Because the remaining demonstrations will rely on outside funding of $1-3 million per site for equipment modifications, they will not occur unless the private sector and federal government share these funds. It is unlikely that the private sector will commit enough resources to complete these essential demonstrations.

Advanced NO_x combustion control concepts are also being developed that may produce further NO_x reductions of up to 50%. Much of this development has taken place in Japan, but EPA, EPRI, the Gas Research Institute, and several boiler vendors have initiated laboratory activites to translate the technology to U.S. conditions. These "reburning" or over-firing techniques should also receive increased development and demonstration attention.

c. Furnace Sorbent Injection

Retrofit demonstrations of in-boiler sulfur control technology should be emphasized as a relatively low cost, near-term approach to reducing SO_2 emissions from existing boilers. The research projects conducted to date have shown that the process can reduce SO_2 emissions by 50% or more in utility applications at significantly lower capital cost than conventional flue gas desulfurizaton systems. The lower capacity factors and shorter remaining lives of older, currently uncontrolled plants typically favor a less capital intensive technology. The research to date has also provided engineers with the information needed to design successful injection systems and modify power plant operations to maintain the performance and reliability of the boiler and ancillary equipment despite the substantial increase of solids material in the flue gases. Current research is aimed at imcreasing the effectiveness of the process to improve its economic attractiveness and reduce the quantity of solid waste that needs to be disposed. Much of EPRI's current resources in the dry sorbent injection area are directed at developing the process for injection at moderate or low temperature (i.e., in the back part of the system rather than in the hot furnace). Not only could these processes work better than furnnace injection, but their development will provide more options for utilities that best fit their site-specific requirements and constraints.

These research projects have laid the groundwork for prototype tests at a number of utility boilers in the 50-150 MWe size range. These prototype tests are an integral part of the development process and are necessary to provide confidence for commercial application. The issue here is the impact on performance and reliability of the boiler, particulate control device, and waste disposal system, not just the SO_2 removal efficiency.

Two prototype test programs are currently being planned or implemented. The Ohio Edison/Babcock & Wilcox/EPA project on a wall-fired boiler is in the detailed design phase, and EPRI has begun to participate by reviewing the injection system design as well as proposing complementary tests that might be funded by the Institute to round out the EPA program. EPRI and EPA are currently considering a cosponsored project to evaluate furnace sorbent injection on a tangentially-fired boiler with various sorbents, coals, injection systems, and particulate control device upgrades. We estimate that an additional four prototypes will be necessary to quantify the sorbent injection technology over the range of boiler types, sizes, coals, and injection processes that should be considered.

Unfortunately, the development of this technology is limited by the lack of funding necessary to implement these planned prototypes. Less than 40% of the approximately $85 million necessary to develop and demonstrate this technology over the next few years is budgeted by the Federal, state, and private sectors.

3. Gas Stream Cleanup

EPRI's hot gas filtration development efforts focus on gas filters for use in PFBC power plants. PFBC plants require the combustion gases to be cleaned of particulate before they enter the gas turbine to prevent erosion and fouling of gas turbine blades. EPRI shares the DOE's conviction that the most cost-effective way to clean PFBC gas is to do it at one location, ahead of the gas turbine, thus avoiding the need for a large, conventional post-gas turbine baghouse or electrostatic precipitator. EPRI's program began with analytical work and bench-scale testing in 1978. The early work identified porous ceramic filter media and electrostatic precipitators as the most promising candidates for the gas conditions of the PFBC turbocharged boiler (800°F, 10 atm) Success at the small scale has led to a new program to provide large-scale confirmation of the technology in the Grimethorpe PFBC pilot plant in England during 1986 and 1987. Two types of ceramic filters are to be tested there; woven ceramic bags and rigid porous filter cartridges.

As a quid pro quo for U.S. participation in the Grimethorpe filter test, the British Grimethorpe project sponsors will be providing the DOE and EPRI with access to all information resulting from the project. The minimum U.S. participation level required to gain access to this information is $10 million, split equally between EPRI and DOE. In order to be certain of the availability of this critical performance data to the U.S., both EPRI and DOE must commit to funding their respective portions of the new work to be done at Grimethorpe. For EPRI, this entails the design, installation and testing of the filter module described above. For DOE, this entails the design, installation and testing of a new coal water feed system.

The DOE has built and plans to test a large high pressure (10 atm), high temperature (1600°F) electrostatic precipitator (ESP) on the New York University (NYU) PFBC test unit in 1986. This ESP is unique in the world in that it is built with plate and wire electode technology representative of full-scale, commercial ESP systems that would be used in PFBC power plants. It would be highly beneficial to U.S. utility companies and PFBC system developers to have this ESP tested at 10 atm and 800°F to simulate PFBC turbocharged boiler operating conditions. This would verify theory regarding the ability to achieve high field strengths at the high gas densities existing in the first-generation PFBC turbocharged boilers. If such a joint DOE/EPRI test could be conducted in 1986, ESP technology would be available for PFBC turbocharged boiler power plants several years earlier than current development plans allow.

In conjunction with three leading potential PFBC equipment vendors, DOE plans to test three candidate gas filters in the NYU PFBC in 1986 (a ceramic cross flow filter, a granular bed filter and an electrostatic precipitator). The existing funding for this test will allow the accumulation of 250 hours total operation time on each gas filter. In EPRI's experience, this is inadequate time to thoroughly qualify new systems and conduct meaningful tests. This is especially true for the ESP because the performance of this type of filter normally degrades with time (and may not become steady for up to 2000 hours) as the discharge and collecting electrodes become fouled with ash deposits. In order to assure the collection of quality data, the DOE should be prepared to increase the scope of these filter tests to allow the operation of each device for the minimum time required to gain confidence in the component operability, to reach steady state operating conditions and to gather valid performance data for commercial plant design.

DOE should commit to the design, manufacture, installation and testing of an alternative gas filter in the EPRI Grimethorpe filter vessel after the conclusion of the EPRI test program. For comparatively small incremental funding, DOE would be able to scale-up and test the best NYU device by a factor of ten. Such a filter test could be accomplished in late 1987.

Extrapolation of the test and design data arising from the Grimethorpe filter test to commercial scale filters is a critical need presently not being filled either by DOE or EPRI. A new program to perform engineering and conceptual design of commercial filters should be undertaken using the performance results from the Grimethorpe filter tests. These new filter designs would be incorporated into exsiting conceptual plant designs and the effect on plant capital cost and efficiency evaluated.

4. Waste Management

Little attention has been given to date to secondary pollution questions associated with air pollution control, notably compliance with Clean Water Act/-NPDES and RCRA. In addition to a very large increase in both solid and liquid waste products created by retrofit control requirements, these requirements will produce by-products of different characteristics--e.g., more soluble sodium and calcium in waste solids from furnace limestone injection than conventional wet limestone scrubbing.

The FY1987 DOE budget request in the waste management area is limited to the completion of several on-going efforts primarily in the sampling and characterization of organic and inorganic species in wastes produced by the "emerging" technologies, and studies of the energy potential from coal preparation wastes.

During 1985 EPRI initiated a major project in management of solid waste materials from the new SO_2 control technologies. This project focuses on the by-products from spray drying, atmospheric fluidized bed combustion, limestone furnace addition, dry sodium addition and advanced physical coal cleaning. Within the 3 year project are activities dealing with information surveys and assessments, waste characterization, leachate testing, conceptual designs, case studies, and utilization options. This project provides an opportunity to coordinate the two programs.

Another opportunity for cooperative efforts is in the waste utilization area. We strongly encourage the continued funding of the Ash Utilization Design Engineering Textbook, as a mechanism for technology transfer to the engineers of tomorrow. The EPRI staff will work closely with the DOE Project Officer to provide input in this effort. This textbook project marks the return of the DOE into the waste utilization area after an absence of several years.

EPRI also recommends that DOE remain active in developing waste utilization alternatives. Private sector efforts are moving toward establishing a sould basis for choosing ash as an alternative raw material for road bases, landfill, structural aggregate, and cement substitutes. This may require several large demonstrations to develop generic (rather than site-specific) information. The using industries (highway/building constructors, etc.) are fragmented. No easily identified commercial entity exists to fund such work, but the cost savings and resource conservation value to the nation could be substantial.

Similarly, resources from ash (particularly aluminum, iron, gallium, and vanadium) have the potential to meet a large portion of national needs which are currently met by imports. Many of the benefits (balance of payments, freedom from foreign sources, national security, price stability) are difficult for private commercial funding sources to quantity and show an economic return. Federal support ot such objectives is appropriate and essential.

EPRI has been funding the development of the direct acid leaching (DAL) process to recover metals from fly ash since 1979. The next step in the commercialization of this technology will be the construction of a 1500 lb/hour pilot plant that will cost $8 million to build and $1-5 million to operate. We would encourage both federal and private industry support to bring this technology closer to commercial success.

B. Advanced Research and Technology Development

1. Materials and Components

a. Materials

EPRI's projects in materials behavior in coal-based energy systems cover the following areas:

1. The lifetime of components in existing pulverized coal boilers: prediction of available life and methods of life extension. In general, these lifetimes are creep-limited.

2. Materials for heat-exchangers (gas coolers) in gasification combined cycle (GCC) plants. This has two thrusts: (a) determining the maximum acceptable temperature of existing materials (including surface treatments) and (b) developing materials coatings to allow this temperature to be increased. It has been shown that "down-time corrosion" due to the condensation of moisture on the cool tubes is a matter of considerable importance.

3. Coatings for gas turbine heat components. Industrial and utility gas turbines may suffer accelerated attack due to the presence of impurities in the fuel or the air. Improved coatings offer a method to combat this.

4. Erosion and erosion-corrosion of gas turbine components with reference to PFBC expander turbines. This work aims to define the lifetime of components as a function of the particle loading in the gas stream, to determine the minimum performance demanded of the hot gas clean-up system. The synergistic role of the presence of alkali salts in the gas stream has also been studied. The effect of this is to limit the maximum bed temperature that can be tested. This last factor is important principally for combined cycle PFBC. The turbo-expander in a turbocharged PFBC should be below the temperature range in which alkali induced corrosion is important.

5. Corrosion of in-bed components in fluidized bed combustors. This work has continued for several years, showing that sulfidation-oxidation corrosion is possible in the bed, even at nominally high excess air levels. Criteria to limit the attack in steam-raising FBC units have beenn developed. Advanced steam conditions and high temperature air heater systems present greater problems.

6. Erosion of in-bed components in fluidized bed combustors. This is the most important problem for both AFBC and PFBC. Studies are designed to identify improved design and operating procedures to minimize the metal loss. Additional work is aimed at determining the mechanism of the in-bed erosion process.

7. Development of refractory systems for slagging gasifiers.

There should be significant Federal involvement in those areas where the systems being investigated by the Federal government differ significantly from those being studied by EPRI. Thus, air-heater FBCs are of no great interest to EPRI at the moment, and thus our corrosion work is winding down. There should be more Federal effort. Erosion may well be a greater problem in smaller industrial AFBC boilers, in part because of the generally lower temperatures; these are not being studied in any detail by EPRI.

There have been joint materials programs at Grimethorpe. Work at national laboratories has also been jointly funded in some cases.

Industry-DOE interaction should be of significant benefit to both. DOE can orient the efforts of industry, and engage in technology transfer from one activity ot another: this is often difficult for industry along. The national laboratories are an important reservoir of talent able to conduct research on the more fundamental aspects of materials behavior in those severe environments.

b. Components

EPRI research into components, is limited to major components such as induced draft fans, feed water pumps, and pulverizers. A major area of interest is the wear of these components, and the activities of DOE in the mechanisms of discrete particle flow and in the stability of coal-water mixtures are clearly of importance.

C. Combustion Systems

1. Atmospheric Fluidized Bed Combustion

Development of Atmospheric Fluidized Bed Combustion (AFBC) has proceeded quickly during the past ten years from the small process confirmation size (e.g. EPRI/B&W 6' x 6' Development Facility) the engineering prototype (TVA/EPRI 20 MWe Pilot Plant), and now to three 100-200 MW utility demonstration projects at TVA, Northern States Power and Colorado-Ute. Widespread commercial use of AFBC technology is also now evident at the industrial scale, with many new industrial cogeneration and utiliy retrofit projects in the design and construction stage. The capabilities of AFBC which have sparked this interest include (a) less sensitivity to fuel quality, enabling low grade/waste fuels to be burned, (b) ability to control SO_2 and NO_x within the combustion process and, (c) capability to be designed in multiple sizes and configurations with minimal cost sensitivity.

In each AFBC demonstration the utility industry is funding the largest portion, with EPRI and the suppliers sharing the first-of-a-kind costs. DOE's $30 million for the TVA/Duke Power/State of Kentucky demonstration is an important contribution to the financial closure of that project. Federal appropriations were also used to pay for nearly half of the $68 million TVA/EPRI 20 MWe AFBC Pilot Plant. In addition, DOE's industrial FBC demonstration programs at Georgetown and Great Lakes during the late 1970's and a mine-waste burning FBC in Shamokin, Pennsylvania, have helped further establish the technical confidence level.

In addition to sharing in the first-of-a-kind costs for the utility FBC demonstrations, the utility industry, equipment suppliers, and EPRI are jointly participating in:

- Test programs at each utility demonstration.
- Further design enhancements at the 20 MWe AFBC prototype.
- Coal and sorbent characterization and testing in order to establish a FBC design data base for all types of coal.

In these programs, coal companies and utility companies are supplying coal, sorbents, and testing personnel while EPRI, TVA and equipment suppliers are sharing in the costs of the test programs.

Though AFBC is proceeding into commercial application, considerable opportunity for continued DOE support exists. This support should be geared toward circulating fluidized bed demonstration test programs at both industrial and at a utility scale, FBC solid by-product utilization, and characterization of additional non-coal fuels. The former activity is needed to establish the engineering basis for large utility circulatinb bed boiler designs. Operating industrial scale units are inadequately instrumented to render the key scale-up data needed. The latter two are appropriate for DOE to support due to crossing institutional boundaries necessary for a cooperative effort. Examples are use of municipal/industrial waste as a fuel for power generation and private industry use of utility by-products. Developing a technology base in these areas is essential before such industrial/municipal/utility coordination could be implemented. However, there is insufficient incentive to invest in this area of national energy interest at this time.

2. Pressurized Fluidized Bed Combustion

External and internal forces of change are causing utility companies to adopt altered generation expansion and retirement strategies. There is a strong trend toward smaller new-unit size plus utility priority on uprating the capacity of exist-lowest possible cost. The advantages of small size and rapid construction are manifested by better matching of load growth and reduced construction work in progress. Measured in terms of equivalent capital cost, these benefits are equivalent to a reduction of 20% to 30%. Pressurized fluidized bed combustion (PFBC) offers the opportunity to add these advantages to the inherent advantages of AFBC, namely fuel flexibility and simple environmental control.

In order to rapidly commercialize PFBC technology with minimum technical risk, EPRI is dedicated to developing the PFBC turbocharged boiler. This PFBC technology, although not as efficient as second-generation combined cycle plants, also offers the advantages of shop fabrication, barge transportability and rapid field erection so that units of 150 to 250 MWe can be quickly added to a system. The system is applicable either as a new unit or as a retrofit; as a retrofit, it can either replace existing oil- or gas-fired boilers in their entirety or it can uprate existing units by supplementing steam-supply-limited boilers. In the PFBC turbocharged boiler, convection banks reduce the gas temperature to 800°F before it leaves the boiler. This lower temperature allows the use of near-conventional gas filters to remove particulates from the gas, minimizes turbine blade erosion and eliminates the need for expensive, high-temperature, refractory-lined gas pipes, waste heat boilers and large, conventional filters after the gas turbine.

Although the PFBC turbocharged boiler has less risk than the PFBC combined cycle at today's state of development, considerable effort is still required in both types before these systems can be widely adopted by the utility industry. Continued operation of two key pilot plants in England and Sweden have shown that the key technical uncertainties in PFBC are the design of in-bed tube bundles, the transfer of solids streams across a high pressure boundary and the overall control of an integrated PFBC/gas filter/gas turbine system.

The two large-scale facilities presently available for resolving these problems are located at Grimethorpe, England and Malmo, Sweden. The Grimethorpe facility was originally operated jointly for the gpvernment of the U.S., U.K. and W. Germany by the International Energy Agency (IEA). In 1985 the unit became private when its ownership and control were transferred to the British National Coal Board and the Central Electricity Generating Board and it was rechristened the Grimethorpe PFBC Establishment (GPFBCE). The Swedish plant is privately funded and operated by ASEA-PFBC, a unit of Stal Laval and ASEA.

Additional U.S. participation is being arranged for by a U.S. boiler vendor; either Babcock & Wilcox or Foster Wheeler will provide a new in-bed tube bundle of their own design for performance and reliability testing by the GPFBCE. A 500 hour test period in 1987 will use U.S. coal and dolomite and will provide data for commercial PFBC unit design in the U.S.

Conceptual designs and cost estimates of commercial plants have been created by various potential vendors of boilers, gas filters and gas turbines in conjunction with engineering firms using the results of the Grimethorpe experience. The results of each study indicates that PFBC is among the lowest cost clean coal alternatives for the production of electricit, particularly through repowering existing power plants.

The ultimate goal of the pilot plant operation and commercial design work is the demonstration of a full scale (ca. 100 MWe) PFBC turbocharged boiler on a utility system. Since, mid-1985, Wisconsin Electric Power Company (WEPCO) has been evaluating the conversion of their 83 MWe Port Washington #5 unit to PFBC turbocharged boiler operation. This project embodies all of the aspects of the technology as identified by Brown Boveri, Foster Wheeler, and Research Cottrell for EPRI in a 1983-1984 study. As defined by WEPCo and the other team members, this project will cost about $90 million. A joint public/private initiative under the DOE Clean Coal Technology program with WEPCO, EPRI and the other team members is required to bring the project to reality. This project will provide full commercial scale demonstration of the technology and provide the design data base needed for broad commercial use in the 1990s.

3. Alternative Fuels

Coal-water slurries have been developed in recent years as a means of increasing the efficient use of coal. The two main types of coal slurries are those developed for long distance transportation and slurries which can be fired directly as a replacement for oil in oil design power plants. Both types of coal slurries have developed to the point of commercial readiness.

Transportation slurry is well developed and is used at Salt River Project, Nevada Power Company, Los Angeles Department of Water and Power, and Southern California Edison's Mohave station where slurry with about 50% coal and 50% water is transported by pipeline for several hundred miles from the mine to the power station. After partial dewatering, the coal is pulverized and fired.

Direct combustion coal-water slurry fuel (CWSF) contains about 70 wt.% coal, 20 wt.% water and 1 wt.% additives and can be fired directly almost as if it were heavy fuel oil. The development of CWSF has progressed rapidly and the technology appears ready for widespread commercial use. CWSF was developed primarily to reduce U.S. dependence on foreign oil and reduce fuel cost through displacement of oil with lower cost coal. The pace of commercial growth of CWSF has, however, been disappointing. This is a consequence of both perceived changes in oil availability, oil consumption reduction, and by dropping oil prices. As a result, the current price differential in favor of CWSF is not large enough to motivate potential users to switch. In addition, the perceived risk of changing from an "old" to a "new" fuel and the uncertainty of future energy scenarios make it difficult for processors who must scale up production from existing pilot plants to production plants to raise venture capital and the resulting chicken-and-egg problem between slurry processor and slurry user continues to hinder market growth.

To demonstrate the full potential of CWSF as an oil replacement and reduce the risks associated with conversion of oil design power plants to CWSF, a utility scale demonstration is required. Such a demonstration would allow integration of R&D completed to date by both DOE and EPRI in such areas as slurry characterization, development of utilization guidelines, and testing of slurry handling, pumping and firing equipment. From a regulatory standpoint, it is essential that boilers converting to CWSF be permitted to meet their existing emission requirements and not be forced to meet New Source Performance Standards (NSPS). Otherwise, commercial acceptance will be minimal.

4. Combustion Technology

Areas requiring additional effort include:

- Characterization of coal ash chemistry and its effect on combustion.
- Standardization of slagging indices.
- Effect of coal particle size on fouling/slagging.
- Effect of coal variability on power plant performance.
- Combustion diagnostics and effect on power performance.

Achievement of these objectives, which may be further accentuated if coal cleaning and switching are increased to meet emission control requirements, will first require expanded combustion testing facilities. These should include a 100 million Btu/h facility whose results could be directly extrapolated to commercial scale furnaces and boilers. It is also essential that smaller facilities be instrumented to measure the transient chemical and physical parameters throughout the combustion process as well as the properites of the resulting gaseous and particulate products. This capability could, for example, apply state-of-the-art measurement techniques developed with DOE support at the Sandia Combustion Facility. It might be most effectively implemented in conjunction with a stable university research program to achieve much needed national centers of excellence in coal science.

D. Fuel Cells

1. Fuel Cell-Gasification

Fuel cells are modular, environmentally acceptable power plants that offer the most efficient use of petroleum and natural gas in the near-term and coal-derived fuels in the longer-term.

Phosphoric acid fuel cells are expected to achieve commercial status by 1990. A market potential of 45,000 MWe is projected for the year 2000 with savings approaching 90 x 10 barrels of oil (equivalent) per year. The importance of this technology to the electric utility industry is described in separate testimony provided by the Fuel Cell Users

Group of the Electric Utility Industry. Further evidence of the importance of phosphoric acid fuel cells to the electric utilities is provided by the increased commitments of five Japanese and two U.S. manufacturers to large scale demonstration and commercial prototype projects.

However, the commercial success of phosphoric acid fuel cells is not assured and will depend upon continued technology improvements to achieve the reliability and the capital costs necessary to penetrate the market and achieve the projected benefits. The absence of any funding for phosphoric acid fuel cells in the Department's FY87 budget ignores the needs of ongoing programs as well as the progress being made under the coordinated support of DOE and EPRI. These efforts if sustained at current levels promise to achieve the cost targets while improving the power plant efficiency from the current 40% to as much as 47%. Beyond this, the integration of fuel cells with coal gasifiers needs to be explored to confirm the projected coal to AC power efficiency of 40% or more. EPRI will continue to support the development and commercial introduction of phosphoric acid fuel cell power plants during the 1986-1990 time period.

EPRI also supports the longer-range molten carbonate and solid oxide fuel cell technologies. We feel that the Department's FY87 request for these technologies is inadequate. The approximately 60% reduction from current levels is inconsistent with the longer term higher risk nature of these technologies.

E. Magnetohydrodynamics

EPRI continues to strongly recommend a continuing DOE open cycle magetrohydrodynamics (OCMHD) program to support the activities at the Component Development and Integration Facility (CDIF) in Montana, the University of Tennessee Space Institute, and the necessary subsystem development programs to provide hardware for testing at these facilities. A federal investment of $35-40 million annually for at least the next 3-5 years is warranted. Such a program should focus on expanding an existing facility such as the CDIF into a fully integrated system test to assess the potential of OCMHD technology. Without such an integrated systems test, the technical readiness of the technology will remain uncertain. Depending on the success of this integrated systems test, it may be appropriate to develop a new larger scale facility

EPRI has had a modest R&D program in OCMHD, concentrating on the development of the MHD channel-inverter interface and the power conditioning of the inverter output to be compatible with electric utility system requirements. In addition, we have supported numerous design studies to estimate the performance and costs of potential commercial systems. Although we presently do not see a large economic "carrot" for this technology without further development, high efficiency systems for utilizing coal in an environmentally acceptable manner clearly are in the national interest and are consistent with DOE R&D objectives and priorities.

Finally, EPRI has been considering an MHD approach wherein coal is first gasified, as discussed earlier, cleaned of its particulate and sulfur, and then fired either with oxygen or air prior to entering the MHD channel. This approach is similar to that being taken in the Soviet Union, however, we would be combusting syngas from coal rather than natural gas. In this way, we could eliminate chemical regeneration requirements of the seed material and eliminate potential slag in the channel and downstream equipments. This concept may offer an interesting option to the conventional coal-fired MHD approach.

In summary, we believe that integrated test facility data should be obtained and design studies conducted before a new facility commitment is made. If this were to become a key objective of the DOE and EPRI activities, such definition should be forthcoming within the next 2-3 years. With other advanced coal technologies emerging, it would appear that this would be a reasonable time frame for such a decision.

F. Coal Liquefaction

1. Once Through Methanol

For many years, EPRI has supported work on the Once Through Methanol (OTM) concept as part of its program to develop the Integrated Gasifier Combined cycle (IGCC) as a means of producing clean coal derived power. OTM refers to the coproduction of methanol and electricity in IGCC plants by partial conversion of the synthesis gas. Studies have shown that OTM produces methanol at a lower cost than other synthetic liquids due to the use of incremental gasifier capacity, avoidance of water gas shift, and the elimination of gas recycle which would ordinarily be required for methanol synthesis. OTM requires a methanol reactor which can convert the carbon monoxide rich gas produced in coal gasification.

A demonstration of this technology is now being planned that will use the existing TVA Muscle Shoals Texaco Gasifier. The methanol conversion technology selected is based upon the Liquid Phase Methanol (LPMeOH) reactor. The design is based on the successful 40 day run completed last year at Air Products' LaPorte PDU under the DOE funded project. EPRI has sponsored extensive planning and engineering studies in addition to gas cleanup testing at the TVA site. The overall project, including design, construction and a year of operation will cost about $40 million. EPRI understands that half of the funding will be requested in a proposal by Air Products and TVA to the Clean Coal Solicitation with the balance provided by EPRI, TVA, and other interested parties.

ATTACHMENT C

EPRI and the utility industry have strongly supported the objective of a federal/private sector partnership to ensure the accelerated demonstration of clean coal technology. This objective was clearly reflected in the Clean Coal Technology portion of Public Law No. 99-190.

EPRI is concerned, however, that the Department of Energy's (DOE) February 17 Program Opportunity Notice (PON) for Clean Coal Technology Demonstration Projects may not be successful in achieving this objective. More than a year ago the utility industry and its suppliers identified nearly $2 billion in clean coal technology demonstrations to DOE for which they were prepared to provide 50 percent or more cost sharing. The confusion which has been created by the language of the PON is, however, discouraging many of these planned initiatives.

Faced with these circumstances, we encourage DOE to simplify and clarify the conditions of the PON with respect to the stated intent of Public Law No. 99-290, as described in the next paragraphs.

From an electric utility perspective, the areas of greatest concern and confusion in the PON may be summarized as follows:

(1) The cost-sharing requirements and provisions for recoupment of the government's investments do not account for the variety of projects likely to be proposed. Neither do they indicate an understanding of the possible actions by regulatory bodies empowered to control the rate of return on public utility investment. For example, a project which proposes an emission control improvement on a utility boiler may not result in increased revenues but only in decreased emissions. Does the repayment requirement mean that DOE would attempt to attach the utility's normal revenues from power productions? Conversely, would the unlikelihood of repayment through increased revenues place such projects at a disadvantage in competing for DOE participation?

Your statement on February 18 to the Senate Energy and National Resources Committee indicating that DOE expects repayment only "if a project is successful and makes a profit" is not reflected by the current PON. As a result, it is not yet clear that Federal partnership funding will be directly available to reduce the costs of first-of-a-kind projects or to provide the incentive for electric utilities to take the risks associated with these ventures.

(2) The PON requires information that is neither warrented by the nature of this cost-shared demonstration program nor reasonably available at this time. Identification of second and third tier subcontractors, details about competitive procurement for contracts, discussions which verify regulatory compliance and detailed statements regarding widespread commercial use are examples of information often not available to utilities and their yet developing business relationships. I would recommend more latitude for estimating potential commercial use.

(3) The PON also seems to be directed at proprietary equipment or processes and discourages demonstrations intended to verify the performance and reliability of engineered emission control modifications to power plants. These retrofit demonstrations are essential to the confident use of clean coal technology, but they are discouraged under the PON because they are not a specific hardware product, nor are they represented by a single vendor with a broad marketplace objective.

(4) The potential for widespread deployment may be legitimate DOE consideration in selecting a specific project or technology. However, the requirement that a project sponsor who might be a user of a technology demonstrate the existence of a market does not seem appropriate. A user may not be able to provide the extensive data and analysis called for in the PON to show whether a technology will be used in many different applications. In fact, actual use in a commercial market, like the electric utility industry, may be the best evidence of potential market acceptability.

(5) Similarly, the requirement that a proposer conduct a full scale analysis of the specific environmental impacts of a proposed technology, based on deployment throughout various regions of the country, is not realistic. Identifying the environmental impacts of a specific project seems proper and necessary. However, a proposer, particularly an electric utility, cannot realistically anticipate the impact of a given technology on the environment in whichever regions of the country it may ultimately be commercially applied. At the very least, this broader estimate should be a joint federal/private responsibility - consistent with the partnership intent of the Clean Coal Technology Program. Further, it should be limited to those projects finally selected.

Encouraging the greater use of coal in an environmentally acceptable manner, assisting in the accelerated development and application of improved technologies, and assuring the improvement to the environment that will result from successful demonstration are all benefits to be gained by the nation as a whole. Unfortunately, the current PON evidences little recognition of these public benefits, yet assumes the marketplace and offerers will financially benefit even where real costs to projects cannot be counted. The PON should recognize the self-policing mechanisms inherent in at-risk cost sharing programs with the private sector, rather than focusing on dubious and costly predictions whose evaluations will, at a minimum, delay ultimate control awards and could misdirect the limited resources available to the Program. The plant demonstrations are being built to obtain performance data.

The importance of the DOE Clean Coal Technology Program has been further underscored by the January 8 "Joint Report of the Special Envoys on Acid Rain." The report endorses positions long encouraged by the utility industry and reflected by the clean coal technology demonstration program authorized under Public Law No. 99-190. Namely, that environmental protection can best be achieved through use of clean coal technology rather than ineffective plant modification that compromise both productivity and the environment. Second, accelerated demonstration and implementation of these technologies by regulated utilities will require cost and regulatory incentives not available today.

The DOE Clean Coal Technology Program is an essential first step in implementing these progressive recommendations which recognize the achievements by the utility industry and DOE to better understand the nature of the acid rain issue and to develop technologies which more cost effectively address the full range of environmental issues facing coal utilization. EPRI alone has invested $500 million to date in these achievements.

Unfortunately, EPRI's ability to sustain our planned investment in clean coal technology, as the central R&D organization of the electric utility industry, is severely constrained today by the financial condition of many of our utility members. This results primarily from the difficulties and delays being experienced in bringing nuclear power plants into service and is unlikely to be resolved in the near future. This places all the more importance on an effective Federal/private partnership to complete the progress in clean coal technology.

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Edward L. Addison
President

the southern electric system

July 1, 1986

Senator James A. McClure
Chairman
United States Senate
Committee on Energy and Natural Resources
Washington, DC 20510

Dear Senator McClure:

Thank you for giving me the opportunity to supplement my presentation to your hearings on clean coal technology development and strategies for acid rain control. The questions you provided with your letter of June 13 are greatly appreciated, and 40 copies of my answers are attached as you requested.

If I may be of further assistance, please feel free to call on me. You and your colleagues are to be commended for holding these important and timely hearings, and I wish you well.

Yours very truly,

E. L. Addison

bmj

Enclosures

RESPONSES TO
QUESTIONS SUBMITTED TO
EDWARD L. ADDISON

HEARING ON
CLEAN COAL TECHNOLOGY AND ACID RAIN CONTROL

Q1. EPA Administrator Thomas, on behalf of the Administration, stated that,

> "we do not yet believe that the current state of knowledge can sustain any judgement with respect to the level of emission reductions needed to prevent or eliminate damage."

Do you agree with this statement?

A1. Yes. This statement is accurate. Mr. Thomas is responsible for major portions of the National Acid Precipitation Assessment Program (NAPAP), the most ambitious and comprehensive acid rain research program in the world. His statements are credible and defensible. Atmospheric transport models and attempts to validate those models have progressed dramatically since acid deposition research began in earnest in 1980. However, it is not possible at this time using state-of-the-art scientific tools to say how far pollutants travel, where they come down, what is their concentration, what is their final chemical form, or what are their impacts. Until these relationships are known with better certainty, an emissions control program cannot be designed to "prevent or eliminate damage."

Q2. EPA Administrator Thomas added,

> "this is true even for the area of greatest scientific understanding, sulfur emission and surface water acidification. In the area of the impact of acid deposition on forests, we have yet to determine if a cause and effect relationship exists."

Do you agree with this assessment of current knowledge?

A2. Yes. This statement also is accurate. Citing the most recent NAS report released in March, 1986, the current scientific data on forest decline in the United States do not identify acid deposition as a major cause. These data suggest that ozone, lead, harsh winters and drought all combine to cause the present forest stress. Acid deposition may be involved, but its role is unclear.

The role of sulfur emissions in surface water acidification also is still unclear. Many lakes and streams receiving identical rainfall have vastly differing acidity levels and fish populations. The role of the surrounding soils and geologic formations evidently is very important in determining a lake's or stream's acidity. (See Electric Power Research Institute study entitled, "The Integrated Lake Watershed Acidification Study.") The recent NAS report also states that over the past 50 years some lakes have become more acidic, some less, and others have remained the same. Determining a cause/effect relationship at this time is premature based on available scientific data, as Mr. Thomas said.

Q3. On the basis of current knowledge of the causes of acid rain, in your judgement, can we formulate a control strategy that will assure achievement of the intended mitigation of acid rain once the prescribed control investments have been made? In other words, can we determine what pollutants need to be controlled, the size reductions that are called for, where the reductions should take place, and over what timeframe they should be implemented?

A3. No. (See the answers to the first two questions.) At this time, based on the scientific data available, it is not possible to determine what pollutants need to be controlled and to what levels they need to be controlled or the size of reductions needed in order to achieve specific changes in acidity of rain.

Q4. There has been considerable discussion of the need to place emphasis on the development of clean coal technologies with retrofit application. For example, the Special Envoys' Report emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

EPA Adminstrator Thomas emphasized in his testimony that "the most important application category for the focus of clean coal technology development would be the coal-fired retrofit application." Do you agree?

a. In your judgement, does the DOE Clean Coal Technology program adequately reflect this need? Or does the program place too much priority on technologies applicable to new construction?

b. Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control? Should they be?

A4. The electric utility industry needs clean coal technologies that are applicable to both existing units and new sources. For immediate emissions reductions, technologies which focus on retrofit applications may be somewhat more important. However, as utilities evaluate technologies for future construction to meet increasing power demands, new technologies will become more important. Some of these, not initially regarded as retrofit technologies, may be capable of retrofit applications at existing sources.

As the Congress structured the Clean Coal Technology Program, it is capable of meeting both needs. However, in the DOE implementation of the program, the emphasis appears to have shifted toward newer plants. We do not believe that too much emphasis is placed on the technologies which will be used for new construction, but perhaps too little has been placed on retrofit technologies.

Some, though not all, of the clean coal technologies funded by DOE will be appropriate for acid rain control. Some of the technologies may or may not achieve emissions levels consistent with new source performance standards. However, those may also be some of the technologies which are capable of reducing emissions in the shortest period of time.

We believe many of these new technologies have the capability of achieving emissions reductions, and, for this reason, they provide the connection between the Special Envoys' Report, Clean Coal Technology, and emission control interests.

Q5. Under what circumstances will life-extension result in reduced atmospheric emissions?

A5. In the past decade there has been a 28% reduction in SO_2 emissions nationwide. A recent EPRI study conservatively indicates that 76% of the pre-NSPS coal-fired capacity in the U.S. could remain in service 20 years beyond the normally assumed 40-year service life without causing SO_2 emissions above this reduced level. This result was obtained using a 2.3% average U.S. annual peak energy demand growth rate and assumed no introduction of advanced coal technologies. For life extension to result in reduced emissions, it would include modifications to the combustion process or the addition of coal-cleaning techniques. For example, while Northern States Power Company (NSP) is retrofitting Black Dog 2 with an atmospheric fluidized bed boiler, it is also extending the life of many of the plant components. Emissions are projected to be reduced when this plant returns to service.

Q6. What is the potential that the types of clean coal technologies under discussion will be able to meet New Source Performance Standards without the use of scrubbers?

A6. We believe that three of the technologies are prime candidates to utilize all qualities of coal, including high-sulfur coal specifically, without scrubbers: atmospheric fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC), and the integrated gasification combined cycle (IGCC). Other technologies may be capable of meeting the New Source Performance Standards depending upon the coal utilized, the region of the country in which the utilization is taking place, and other site-specific considerations. It should be kept in mind that pulverized coal firing and scrubber technologies also will be advancing as new technologies are moving toward commercial availability.

Q7. Are the technologies being developed by the DOE clean coal technology program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?

A7. We believe that these technologies are likely to be used because of their many advantages, particularly for new contruction. Because of the uncertainty of demand and the flexibility of clean coal technologies to meet future load growth, we believe these technologies may achieve widespread acceptance in the future without new regulatory requirements.

Q8. Mr. Donald Bauer, on behalf of DOE, stated that performance testing of clean coal technologies under consideration by DOE generally will not be completed until the early to mid-1990s. He concluded with the observation that "if the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options." Do you agree?

A8. Mr. Bauer is absolutely correct. So much of our capital resources would be devoted to immediate compliance with H.R. 4567 that we could not afford to move ahead with clean coal technologies.

Q9. One of the premises behind the Clean Air Act was that industry would gradually retire old facilities and replace them with new installations subject to "new source performance standards." Consequently, there would be a gradual improvement in air quality. In your judgements has this occurred?

In asking this question it is observed that EPA Administrator Thomas, commenting on plant life extension trends, stated that, "this postpones the rate at which new sources will replace existing sources, making New Source Performance Standards a less effective way of reducing overall emissions in the near or middle term."

A9. Certainly the new sources our industry has brought on line since the passage of the Clean Air Act have helped reduce emissions. A number of older sources have changed coal qualities and that also has assisted in emission reductions. If life extension is defined as only refurbishing the status quo and keeping existing components working, then the Administrator is correct. However, if life extension takes on the direction that it has at Black Dog 2, as noted in the answer to Q5, or at Oak Creek Units 1-4 of Wisconsin Electric Company, then emissions do come down substantially at existing sources.

Q10. In your opinions, what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the various legislative proposals before the Congress? For example, is the electric utility industry likely to rely on extension of the life of existing facilities rather than their retirement and replacement with new facilities?

A10. The response of the industry will depend upon the amount of generation needed at given locations on each system and the physical characteristics of each plant. In certain circumstances, such as those noted above with Northern States Power Company and Wisconsin Electric Power Company, the retrofit of a plant that simultaneously incorporates a clean coal technology may be the best answer. In other cases, we would anticipate some companies would elect to switch fuels or put on a scrubber. Companies that have the financial position to undertake a construction program may elect to construct new plants--these would require scrubbers unless the company is willing to risk the use of a technology which probably has not been utilized at utility scale and for which a public utility commission might not approve of the financial risk.

Q11. In your judgement, to what extent is industry's decision to extend the life of an existing facility influenced by regulatory policies? For example, as I understand EPA regulations, at a certain point the costs of retrofitting an existing facility become great enough that it runs the risk of being classified as a new one subject to New Source Performance Standards. Would you comment.

A11. Your understanding of current EPA regulations is correct, i.e., if a unit is significantly modified or reconstructed, it may be classified as a "New Source" and be subject to lower emission standards. With current technologies, retrofitting a unit to meet these lower emission levels requires a substantial capital investment and usually entails further operating penalties as well.

When deciding between retiring or continuing operation of an existing electric generating facility, a utility typically considers system operations and financial factors such as performance, reliability, fuel type and mix, unit size, operating characteristics and restrictions, location, and operation, maintenance and capital costs. It is obvious that the additional costs of meeting New Source Performance Standards will result in a decision to retire an existing facility where the technical and economic benefits of extending service life are marginal. Also, where the benefits of life extension are great and/or other options for meeting electric demand are limited, modifications necessary to postpone retirement will be made. However, most companies are currently only investigating the feasibility of extending the service life of existing facilities and it is too early to quantify the impact regulatory policies will have on the majority of units being considered.

In summary, the decisions will be based on many technical and economic factors, all of which are constrained by regulatory policies.

Q12. The Clean Air Act provides for an extension of compliance dates for facilities that propose to utilize new or innovative technologies to comply with emissions standards. In your judgement, has this authority been effectively implemented by the EPA?

A12. No. To our knowledge, EPA has yet to make use of this authority and has not particularly encouraged the use of innovative technologies for emissions control, with the exception of the limestone injection multi-stage burner (LIMB) technology. We believe that this is a direction that EPA should seriously consider to broaden the scope of the technologies available for cost-effective SO_2 and NO_x control.

Q13. What is the national average cost of FGD retrofit per kilowatt? And, what would be the cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements? What would be the differential cost between implementation of the above options?

A13. The average cost for retrofitting an electric generating unit with a conventional wet flue gas desulfurization unit (scrubber) is $280/kW in 1986 dollars. However, this average is misleading. Based on specific situations, the cost could range between $135/kW and $506/kW.

Based on these figures, Temple, Barker & Sloane, Inc. estimated for the Edison Electric Institute that the cost of acid rain legislation being considered in the House of Representatives (H.R. 4567) will be $5.4 billion annually for the life of the legislation.

There is a total of 1125 units currently in operation, of which 134 are equipped with scrubbers. It is obvious that to retrofit all units with scrubbers would be prohibitive, but it is difficult to estimate the cost of retrofitting all units because premature retirement would be more cost-effective than adding scrubbers in many cases.

Q14. What, in your judgement, are the estimated costs of implementing proposed acid rain legislation? Would you indicate the sources of such cost estimates and whether you agree, or disagree, with such analysis?

A14. Several interested parties have made estimates on the cost of acid rain controls. The Office of Technology Assessment (OTA) estimates $3.8 to $4.9 billion annually. The U.S. Environmental Protection Agency estimates $3.1 to $5.8 billion, and EEI estimates $5.4 billion. Differences will always exist based on assumptions used in the analyses, but OTA, EPA, and EEI do not seem to differ dramatically in their end results.

Q15. What, in your judgement, are the comparative roles of different source contributors of air pollution as contributing factors in acid precipitation? Would you indicate the sources of such information and whether you agree, or disagree, with such analysis?

A15. Please refer to the answers to the first three questions. According to the leading scientists in the field, including primarily the NAS, NAPAP, and the National Atmospheric Deposition Program (NADP), many factors are at work in the environment which contribute to negative impacts, and the roles of specific precursors of acid precipitation are unclear. We look especially to NAPAP to resolve the key questions and define the roles.

It is the belief of EEI that there is already in place a control program for all of these elements - the Clean Air Act. The U.S. EPA Emissions Trends Report shows that the air in the United States is at its cleanest since passage of the Act in 1970. Continued compliance with the Act, plus implementation of clean coal technologies, will ensure continuation of this trend.

Q16. An apparent problem for using clean coal technologies to mitigate acid rain is the timetables assumed to be required for reductions in SO_2 and NO_x. In your view, what is a reasonable timeframe for SO_2 and NO_x reduction? And secondly, which clean coal technologies are likely to be most readily available within that timeframe?

A16. First of all, as noted earlier, there is no scientific justification for the proposed emission reductions and, therefore, both the proposed reductions and the timetable for compliance are entirely arbitrary. Compliance dates for S.2203 or H.R. 4567 are clearly too soon to adopt new technologies, and the only compliance choices will be fuel switching or scrubbers. It will be the middle or late 1990s before commercial viability of several promising new clean coal technologies can be established - including atmospheric fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC), and integrated gasification combined cycle (IGCC) technologies - in the sizes and with the reliability requirements needed by utilities. Thus, we feel that acid rain legislation is premature. It should be delayed until the NAPAP results will permit formulation of a national strategy likely to produce definitive results at costs commensurate with expected benefits. In the interim period, new clean coal technologies can be developed to the point that appropriate applications can be made as needed.

Q17. In your view, is it realistic to expect emerging clean coal technologies to significantly contribute to SO_2 and NO_x reductions prior to the year 2000?

A17. It is realistic to expect that, by the year 2000, several new technologies will be commercially demonstrated and some will be in place and able to make significant contributions to emission reductions. It is very difficult to predict how rapidly the technologies will penetrate the market between now and the year 2000. The AFBC may penetrate more rapidly if some smaller units that are older become candidates for a life-extension program that includes repowering. IGCC may penetrate rapidly depending upon load growth, phased construction needs, and the price of oil and natural gas.

Q18. Having an interest in DOE's solicitation on clean coal technologies, do you believe the range of projects currently reflects the best set of options for future clean coal applications?

A18. Our knowledge of most of the projects is minimal. Two PFBC projects have been submitted to DOE for funding under the Clean Coal Technology Reserve. Both of those projects provide complementary and vital information about the PFBC technology and, in our view, both should be funded. However, overall, the range of projects does not reflect a complete set of options for clean coal use. Notably absent are projects which would test another version of the IGCC as well as technologies enhancing flue gas desulfurization technology. Some technologies could be better represented, as noted in the testimony provided by EPRI for the Committee, to provide the best set of options for future clean coal applications.

Q19. Do you believe DOE's "payback" component of the solicitation has in any way dampened interest in proposing new technologies?

A19. Yes. We believe the payback component significantly discouraged many potential proposers when it first appeared for public evaluation in the draft solicitation in late-January. Since there was no discussion of payback during consideration of funding by the Congress, the proposed language came as a disincentive to many participants who were considering submitting a proposal.

Q20. In your view, does the DOE solicitation effectively bring out of the research community and industry all the appropriate clean coal technologies, particularly those related to retrofit on existing facilities?

As a followup, is it the Committee's understanding that your company was originally prepared to pursue a retrofit project under the solicitation but chose not to continue? Could you comment on your reasons for first thinking of such a project and then your rationale for dropping the idea?

A20. The DOE solicitation does not effectively bring out from either the research community or industry all of the appropriate technologies, particularly those focusing on retrofits. (See the answer to Q18.)

Southern Company decided not to pursue a proposed project to significantly improve existing flue gas desulfurization technology for several reasons, the chief of which was financial. We are in the midst of a very large capital addition to our system and felt that an additional new technology expenditure was not in the best interest of our company at this time.

Q21. Your prepared remarks make it quite clear that current legislative proposals would severely limit industry's ability to pursue a clean coal technology program and meet the legislative timetables for SO_2 and NO_x reduction. How would you propose to approach both goals?

A21. Initially, utilities probably would comply with acid rain timetables by switching fuels or adding scrubbers. This would not only absorb limited capital resources, but also it would commit the utilities to specific compliance strategies (including current scrubber technologies) for years to come. The financial ability to invest in new technologies and the incentive to install new technologies would therefore be deferred for a decade or two, during which the load growth and retirement of existing units would be steadily increasing the need for new technologies which were being deferred.

Q22. You mention a "family of technologies" by the end of the 1990s. From your vantage point, which clean coal technologies are most promising for use within that decade?

A22. Several technologies are promising for use within the decade of the 1990s. Coal cleaning and LIMB technologies may become available in the near term. On a longer-term basis, the AFBC and IGCC technologies are expected to become commercially available, followed later by PFBC. AFBC, PFBC, and IGCC are the most promising in terms of overall application as currently projected.

Q23. In your remarks, you note that clean coal technologies "are expected to offer the utility industry many benefits." Specifically you refer to fuel flexibility, modular and incremental construction of power producing facilities. These advantages appear to carry with them, decreased costs per megawatt. Are the savings associated with these economies a factor in pursuing a clean coal program?

A23. The savings which can be attributed to fuel flexibility, modular and incremental construction are a factor in pursuing a clean coal program. The potential for future savings is the motivation for much of the effort. Shop fabrication and modular construction of PFBC plants should make their costs lower than for conventional pulverized coal plants. Similar savings should occur with the IGCC technology which can also be shop fabricated. We believe quality control will be enhanced while construction time is reduced. The deployment of any new technology will be based on the cost-effectiveness of its application to meet specific requirements.

Q24. In your view, what is a reasonable and practical timeframe for the successful utilization of clean coal technologies at most plants within your industry?

A24. We hesitate to make an answer for the entire industry when the economic justification of each plant is based on specific local conditions. In general, however, clean coal technologies will be applied in several ways. Different technologies will emerge in different time periods, as mentioned in the answer to Q22. Market penetration could start within five years for advanced coal cleaning or LIMB if currently planned demonstration projects are successful. In the early to middle 1990s, AFBC and IGCC may begin to be used as confidence is gained in them. It appears that PFBC could begin to gain acceptance in the middle to late 1990s. These dates mark what appears now to be reasonable times for market entry. It must be kept in mind that cost-effectiveness and reliability are unproven as yet for any of these technologies, and these are prerequisites for market entry. Other factors could influence the prognosis for new technologies. For example, another oil and gas crisis could stimulate coal gasification or liquefaction to the point that technologies which benefit from clean fuels - like fuel cells - could be reconsidered. Thus, the timeframes will vary, and conceivably from as little as five years to over 20 in some cases. Existing plants with scrubbers will continue to be operated until the end of their useful lives.

Q25. You comment that DOE's program opportunity notice hurt many potential projects because of confusion associated with repayment of the federal portion. Subsequent revisions apparently did not mitigate the problem. Are there specific projects, with which you are aware, that were not submitted, and if so, did they reflect technologies not currently represented in the solicitation response?

A25. Congressman Philip R. Sharp, Subcommittee on Fossil and Synthetic Fuels, Committee on Energy and Commerce of the U.S. House of Representatives, recently has contacted the organizations which earlier expressed an interest but finally did not submit a proposal to DOE. Rather than for me to offer information available to EEI, I believe it would be of greater use to your committee to ask Congressman Sharp to provide you with the results of his survey.

7/1/86
0430r

QUESTIONS SUBMITTED TO

JOHN WOOTTEN

HEARING ON
CLEAN COAL TECHNOLOGY AND ACID RAIN CONTROL

1. EPA Administrator Thomas, on behalf of the Administration, stated that,

   > "we do not yet believe that the current state of knowledge can sustain any judgement with respect to the level of emission reductions needed to prevent or eliminate damage."

   Do you agree with this statement?

2. EPA Administrator Thomas added,

   > "this is true even for the area of greatest scientific understanding, sulfur emission and surface water acidification. In the area of the impact of acid deposition on forests, we have yet to determine if a cause and effect relationship exists."

   Do you agree with this assessment of current knowledge?

3. On the basis of current knowledge of the causes of acid rain, in your judgement, can we formulate a control strategy that will assure achievement of the intended mitigation of acid rain once the prescribed control investments have been made? In other words, can we determine what pollutants need to be controlled, the size reductions that are called for, where the reductions should take place, and over what time frame they should be implemented?

4. There has been considerable discussion of the need to place emphasis on the development of clean coal technologies with retrofit application. For example, the Special Envoys Report emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

   EPA Administrator Thomas emphasized in his testimony that "the most important application category for the focus of clean coal technology development would be the coal-fired retrofit application". Do you agree?

   a. In your judgement, does the DOE Clean Coal Technology program adequately reflect this need? Or does the program place too much priority on technologies applicable to new construction?

   b. Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control? Should they be?

5. Under what circumstances will life-extension result in reduced atmospheric emissions?

6. What is the potential that the types of clean coal technologies under discussion will be able to meet New Source Performance Standards without the use of scrubbers?

7. Are the technologies being developed by the DOE clean coal technology program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?

8. Mr. Donald Bauer, on behalf of DOE, stated that performance testing of clean coal technologies under consideration by DOE generally will not be completed until the early to mid-1990s. He concluded with the observation that "if the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options". Do you agree?

9. One of the premises behind the Clean Air Act was that industry would gradually retire old facilities and replace them with new installations subject to "new source performance standards". Consequently, there would be a gradual improvement in air quality. In your judgements has this occurred?

   In asking this question it is observed that EPA Administrator Thomas, commenting on plant life extension trends, stated that, "this postpones the rate at which new sources will replace existing sources, making New Source Performance Standards a less effective way of reducing overall emissions in the near or middle term".

10. In your opinions, what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the various legislative proposals before the Congress? For example, is the electric utility industry likely to rely on extension of the life of existing facilities rather than their retirement and replacement with new facilities?

11. In your judgement, to what extent is industry's decision to extend the life of an existing facility influenced by regulatory policies? For example, as I understand EPA regulations, at a certain point the costs of retrofitting an existing facility become great enough that it runs the risk of being classified as a new one subject to New Source Performance Standards. Would you comment.

12. The Clean Air Act provides for an extension of compliance dates for facilities that propose to utilize new or innovative technologies to comply with emissions standards. In your judgement, has this authority been effectively implemented by the EPA?

13. What is the national average cost of FGD retrofit per kilowatt? And, what would be the cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements? What would be the differential cost between implementation of the above options?

14. What, in your judgement, are the estimated costs of implementing proposed acid rain legislation? Would you indicate the sources of such cost estimates and whether you agree, or disagree, with such analysis?

15. What in your judgement, are the comparative roles of different source contributors of air pollution as contributing factors in acid precipatation? Would you indicate the sources of such information and whether you agree, or disagree, with such analysis?

16. An apparent problem for using clean coal technologies to mitigate acid rain is the timetables assumed to be required for reductions in SO2 and NOx. In your view what is a reasonable timeframe for SO2 and NOx reduction? And secondly, which clean coal technologies are likely to be most readily available within that timeframe?

17. In your view, is it realistic to expect emerging clean coal technologies to significantly contribute to SO2 and NOx reductions prior to the year 2000?

18. Having an interest in DOE's solicitation on clean coal technologies, do you believe the range of projects currently reflects the best set of options for future clean coal applications?

19. Do you believe DOE's "payback" component of the solicitation has in any way dampened interest in proposing new technologies?

20. In your written remarks, you note that Peabody supports the technology recommendations of the Joint Envoy's Report. How realistic is it to expect that clean coal technologies will significantly contribute to SO2 and NOx reductions prior to 1995?

21. You comment on the DOE solicitaton proposals and the apparent dearth of retrofit technologies. To what do you attribute the disinterest in retrofit technologies, particulary given the introduction of legislative vehicles that focus on near-term SO2 and NOx reductions?

22. What technology does Peabody feel is most promising for future coal development, notwithstanding acid rain mitigation?

23. Do you feel that the private sector would develop these technologies in their economic interest without federal government involvement?

24. In your view, is the life extension trend in utility coal-fired facilities, mitigating against implementation of clean coal technologies for acid rain control?

25. You suggest in your remarks that acid rain control legislation currently proposed would quote, "disproportionately increase electrical rates in the Midwest and South..." To what extent do you feel clean coal technology implementation will increase rates? Who should pay for implementation? The utility, the ratepayer or the federal government.

26. In your statement you suggest that there is little concrete evidence that there is "...any widespread danger to aquatic or terrestrial resources..." and acid deposition. If Peabody believes this scenario, what corporate incentive is there to support clean coal technologies for environmental affect mitigation?

RESPONSE TO QUESTIONS
SUBMITTED TO
JOHN M. WOOTTEN
DIRECTOR OF RESEARCH & TECHNOLOGY
PEABODY HOLDING COMPANY, INC.
ST. LOUIS,MISSOURI

HEARING ON
CLEAN COAL TECHNOLOGY AND ACID RAIN CONTROL
COMMITTEE ON ENERGY AND NATURAL RESOURCES
U.S. SENATE
WASHINGTON, D.C.
JUNE 23, 1986

Response #1

Yes, I do believe that the current state of knowledge is inadequate to sustain any judgment with respect to the level of emission reductions needed to prevent or eliminate damage. The question of devising a control scheme for reducing or mitigating any effects of acid deposition requires the resolution of a number of unanswered questions. First, what pollutants are to be controlled to reduce acid deposition? There is no question that nitrogen oxides and sulfur oxides contribute to acid deposition. However, the rate of formation of acid deposition may be controlled by other pollutants such as reactive hydrocarbons and oxidants. In particular, it appears that the chemistry of acid deposition is related to hydrogen peroxide and hydroxyl radicals that are formed as a result of photochemical reactions in the atmosphere. The second question is how much reduction in acid deposition is to be achieved to protect which resources that are at risk. A third consideration is what deposition rate will protect against the acidification process and is it actually deposition or the surrounding environment, such as the soil and vegetation in an area, that affects the acidification process. A final question is whether emission reduction as opposed to mitigation such as liming and restocking of water bodies is the most cost effective approach. All of these questions will need to be addressed in some detail in order to identify the most prudent control plan to provide the greatest environmental benefit through the most cost effective approach.

Response #2

Yes, I agree with EPA Administrator Thomas's assessment of current knowledge. Sulfur emissions and the surface water acidification process are the two areas of our greatest understanding. The level of understanding that we have indicates that the problem of surface water acidification is limited in its spatial impact, limited in the number of water bodies that are being impacted, and does not appear to be a situation where resources are at imminent risk. For example, the National Research Council in its 1986 report entitled, "Acid Deposition Long-Term Trends," commented on the historical trends in the acidification of lakes in the following manner:

> "Based on comparisons of historical data on alkalinity and pH recorded in the 1920's, 30's and 40's, with recent data from several hundred lakes in Wisconsin, New Hampshire and New York, we find that many lakes have decreased in pH and alkalinity and many have increased in pH and alkalinity."

More specifically, the NRC looked at the many factors which would indicate whether lakes in the Adirondack Mountain area of New York had been acidified by acid deposition or not. In conclusion, the NRC stated the following:

> "Because of ambiguities regarding the assumptions employed in the historical New York survey, we cannot currently determine which of these results is more accurate, and hence, we cannot quantify the number of New York lakes that have been affected by acid deposition."

With regard to the impact of acid deposition on forests, I also agree that it cannot yet be determined if there is a cause and effect relationship between deposition and any forest impacts. The National Resource Council also looked at those trends and drew the following conclusion:

> "The roles of competition, climatic and biotic stresses, and acid deposition and other pollutants cannot be adequately evaluated with currently available data."

In summary, the role of acid deposition and its effects on surface water acidification and forest damage have not clearly been demonstrated.

Response #3

No, we cannot formulate a control strategy that will assure achievement of the intended mitigation of acid rain irregardless of the amount of prescribed control investments that would be made. Based on the information provided in responses #1 and #2, we do not know what level of control should be applied, what sources in what geographical areas should be controlled in order to assure which at risk resources will be protected. What we do know about the acid deposition process appears to indicate that there is time to first complete the research that is currently underway under the National Acid Deposition Assessment Plan. Secondly, it appears that the time frame for any widespread, irreversible impacts from acid deposition, if in fact any have occurred, is more on the order of decades rather than years. This would mean that there is time to deploy new technologies to reduce emissions under a more cost-effective and less disruptive program than would result if currently contemplated acid rain legislation were enacted.

Response #4

Yes, I agree that there should be emphasis placed on the development of retrofit clean coal technologies. Although I believe Congress in enacting the Clean Coal Technology Program had placed great emphasis on the retrofit application, the manner in which DOE solicited proposals for the program discouraged respondents from trying to demonstrate retrofit technologies. Three components of the solicitation favored new technologies more than retrofit technologies. These three areas were the requirement for an assessment of the environmental impact of the technology, the need to make a market assessment for the utilization of the technology, and the requirement that the government-funded portion of the demonstration be repaid from revenues generated by the demonstration. Retrofit technology demonstrations, in order to be successful, will require their application to an existing power plant or industrial facility. Because the revenue portion of that facility will already be in place, there will be no new revenues from the application of a retrofit technology and this confused and discouraged respondents. Similarly, utilities, who are the most likely host, are ill-equipped to make major environmental assessments and probably are not equipped at all to make market assessments for the utilization of a technology that may be demonstrated.

No, not all new programs potentially funded by the Clean Coal Technology Program will be appropriate for acid rain control. If the most prudent form of acid rain control is the reduction of sulfur oxide and nitrogen oxide, the Clean Coal Technology Program should provide the highest priority to those technologies which would accomplish that goal. This is not to say, however, that development of other technologies which may not in the immediate future address the control of these pollutants should be discouraged. In the long run, all technologies that burn coal more efficiently and at lower emission levels will have a positive impact on emission reduction, and therefore, acid rain control.

Response #5

The circumstances that will result in reduced atmospheric emissions resulting from the life extension of a utility unit will be that situation where life extension entails modifications that either include control equipment, upgrade existing control equipment, or where modification of the utility system will allow for more efficient operation and thus reduce the overall amount of emissions.

Response #6

There is a large potential that many of the clean coal technologies under discussion will be able to meet the New Source Performance Standards. Any one technology may not provide the level of control necessary to achieve it. However, there may be synergism between different technologies to achieve the required performance level. For example, an advanced coal cleaning application with the retrofit of low NO_x burners, and the injection of a sorbent either in the boiler or the ductwork, may provide more than adequate control to achieve the New Source Performance Standards. The cost of the combined technologies may be below that required to install a flue gas desulfurization device which only provides control of SO_2, leaving nitrogen oxides and particulate matter to be controlled at the present level.

Response #7

Deployment of the new technologies demonstrated by the Clean Coal Technology Program will occur with or without new regulatory requirements. For example, three fluidized bed demonstrations are currently underway in the U.S. today. These three demonstrations were initiated without funding from the Clean Coal Technology Fund. In addition, EPRI has undertaken demonstration work and, for example, the gasification combined cycle program has received a major boost and a major interest from utilities as a result of that program. AFBC and GCC are both systems that utilities have announced publicly that they intend to install or use in retrofit applications at existing facilities. Depending on the timing, a new regulatory initiative will force the deployment of new technologies. However, if reductions are required to be implemented too rapidly, the use of new technology will be precluded. If utilities were given incentives such as tax credits or other investment options, and they were given some guarantee that they would recover their investment in new technologies from their rate-making bodies, then the deployment of the clean coal technologies would be enhanced.

Response #8

Yes, I agree with Mr. Bauer's conclusion that acid rain legislation which calls for compliance in the early to mid-1990s will not provide sufficient time for the commercial demonstration for many of the clean coal technologies. To achieve major emission reduction before the mid-1990s, utilities would have to select a strategy and provide adequate time for its design, procurement and installation, which will require selection of control technologies that are available today.

Response #9

I believe the provisions of the Clean Air Act which requires the control of existing facilities to achieve health and welfare-related standards and the application of New Source Performance Standards to new emission sources has resulted in a marked improvement in air quality. For example, the National Coal Association (NCA) in April released the findings of a study that indicated that SO_2 emissions from coal-fired powerplants had declined between 1980 and 1985 by some 2.7 percent, while coal consumption had increased by 23 percent. NCA indicated that the decline in SO_2 emissions resulted from four factors -- new, lower emitting plants are coming on line, demand for coal-fired power has shifted from higher to lower emitting regions, utilities are burning lower sulfur coal and flue gas desulfurization systems had been added to existing capacity.

EPA Administrator Thomas may be correct that the rate of reduction due to the replacement of older plants with newer, less polluting plants may have slowed due to many factors, both economic and environmental, and that life extension may have a further slowing impact on this trend. However, there is already evidence that at least for some utilities life extension is involving the application of technologies like fluidized bed combustion which will accelerate the emission decrease as these technologies replace existing coal combustion technologies.

Response #10

I am of the opinion that industry's approach to meeting any new acid rain control regulatory requirement will be either to switch fuels or to install flue gas desulfurization equipment. Both approaches have real negative impacts of an economic and social nature. If a utility is forced to install a flue gas desulfurization system, which in many cases will require an investment equal to the investment for the entire original generating plant, then that facility will be operated for an extended period to allow the utility to recover that investment.

It is likely that that facility would have been retired before the end of the new use period to be replaced with by a NSPS plant or even a new technology which not only would have resulted in reduced sulfur dioxide emissions, but the reduction of nitrogen oxide and particulate emissions as well.

Response #11

I believe that industry's decision to extend the life of an existing plant is heavily influenced by regulatory policies. Current estimates are that a plant can be put through a life extension program at a cost of $100-300 per kilowatt of installed capacity. This compares to the construction of a new facility at a cost of approximately $1500 per kilowatt of installed capacity. The life extension approach allows the utility a more economical solution and a more likely scenario for recovering any expenditure in their existing rate structure. If a utility were required to retrofit the existing facility with a flue gas desulfurization device during life extension, this would approximately double the cost of doing the extension, but still may not exceed the point that requires the facility to be classed as a new source.

Response #12

I do not have a sense that the Clean Air Act provisions that allow for extended compliance times when new or innovative technologies are required has been ineffectively implemented by EPA. I think there are limited instances where this provision has been utilized by sources in their compliance effort, and maybe a more active program by EPA would provide a more robust use of the provisions by industry.

Response #13

Peabody does not have a figure for the national average cost of FGD retrofit of installed capacity. However, utilizing Peabody's acid rain model, we can project costs for various acid rain control legislation. For example, for H.R. 4567, we projected that FGD retrofit would be the most cost effective approach for 62,299 MW of capacity. The average cost for installing FGD systems on this capacity was $188 per kilowatt or a total capital cost of $11.7 billion. On a \$/ton of SO_2 removed, this comes to an average cost of \$826. This can be compared to fuel switching for the same bill of \$511/ton of SO_2 removed at a cost of $1.85 billion a year and a reduction of 3.6 million tons. If FGD costs, or alternatively if new retrofit clean coal technologies could be developed which would cost 40 percent less than current technology, the differential between the cost of switching fuels and the cost for technology would be eliminated. As a result, many of the facilities that chose to switch fuels would adopt a clean coal technology. It is not unrealistic to believe that the clean coal technologies will be lower in cost than the FGD costs of today by 40 percent or more.

Response #14
As reported in great detail in my statement, we believe that the cost to implement the kind of acid rain control legislation contemplated in bills such as H.R. 4567 will be approximately $5.8 billion on a levelized annual basis. Irregardless of whose estimate you use, EPA or EEI, the costs will still be in the $3-9 billion a year range for a potential outcome which cannot be guaranteed or at this point even estimated.

Response #15
In December of 1984, EPA issued for the National Acid Precipitation Assessment Program a status report on the development of the NAPAP emission inventory for the 1980 base year. EPA in this document indicated that of 27.1 million tons of SO_2 was emitted in 1980, with utilities emitting 64 percent of that total. For nitrogen oxides, EPA indicated that of the 23.7 million tons emitted, utilities were responsible for 34 percent, non-utility combustion was responsible for 22 percent, and the transportation sector was responsible for 38 percent. If one were to assume that source contributions as a percent of total emissions was directly related to the contribution to acid deposition, then one could assume that these percentages would hold true throughout. However, atmospheric chemistry is not that simple. The conversion of sulfur dioxide emissions to acid deposition is dependent upon the reactions with other co-pollutants in the atmosphere. Therefore, if the nitrogen oxide cycle is responsible for the conversion of sulfur dioxide to sulfate and sulfuric acid, then one must consider the relative importance of that emission in its role as a converter of another pollutant to an acid species.

Response #16
Reasonable time frames for SO_2 and NO_x reduction are dependent upon the effects of SO_2 and NO_x on acid deposition and in turn the effects of acid deposition on the environment. As previously indicated in my responses, it does not appear that the environment is facing a situation of imminent, irreversible damage. Therefore, SO_2 and NO_x reductions can be phased over a considerable amount of time, decades as opposed to years. The present clean coal technology programs will most probably deliver commercially demonstrated technologies beyond the mid-1990s. These technologies can then be implemented as facilities are either retired and replaced with new technologies, or retrofitted on those facilities which are life extended.

If a new initiative on retrofit technologies is implemented, it is likely that many of these technologies would be available by 1995 -- sorbent injection, dry FGD systems and repowering applications of fluidized bed combustion and gasification combined cycle are all likely candidates in this time frame.

Response #17
In my opinion, it is neither necessary nor probable that clean coal technologies will contribute to reducing SO_2 or NO_x in a manner

comparable to proposed acid rain control legislation. Demonstration of a sufficient number of clean coal technologies can be anticipated beyond the mid-1990s. After the year 2000, a sufficient number of utilities' units will be facing replacement and/or life extension to allow for installation of these technologies. Requirements to force significant reductions prior to the year 2000 will preclude the use of new technologies.

Response #18

The responses to the current DOE solicitation do not reflect a broad enough menu of projects to allow for an acceptable number of alternatives for reducing emissions from existing facilities. A solicitation for retrofit technologies should be done in order to broaden the scope of the Clean Coal Technology Program to ensure it covers that portion of sources that are responsible for the greatest amount of emissions today.

Response #19

Yes, the payback component of the solicitation has dampened the interest in proposing new technologies. A source or group of industrial partners is looking for a way to share the risk of demonstrating a technology and not for a loan to market a new product. If the sponsors of a new technology conduct a successful demonstration and it moves to commercialization with some real benefit to the sponsors, then perhaps payback in part is acceptable. However, in most cases it is a utility who is the host, or major sponsor of the demonstration, utilizing a third-party's technology, and therefore, the utility should not be responsible for paying back the federal contribution.

Response #20

It is unlikely that clean coal technologies will contribute to SO_2 and NO_x reductions prior to 1995. It would be reasonable to believe that the clean coal technologies would be adequately demonstrated by 1995 for deployment after the year 2000. It would be after the year 2000 before there would be sufficient retirement of existing facilities or life extension of a large enough population to affect a significant reduction.

Response #21 and #22

I believe the disinterest in retrofit technologies resulted from the requirement for extensive documentation for the environmental impact of the technology and for the assessment of the market impact of the technology, and finally as a result of the repayment provisions of the program. Retrofit technologies typically will have to involve a utility and the use of an existing unit owned or operated by that utility. There will be no new revenues generated from that facility. In fact, the construction and operation of the retrofit technology will undoubtedly add costs and a reduction in revenues from the existing facilities. The extensive documentation required by these provisions of the solicitation as well as the confusion over the repayment provisions resulted in many of the utilities not responding to the solicitation. Peabody believes that one of the most promising future coal development technologies is atmospheric fluidized bed combustion. We have invested our own resources in two of the ongoing AFBC demonstrations -- TVA and Colorado-Ute -- and have made a proposal for assistance in the Northern States Power project.

Response #23

The three AFBC demonstration projects are moving forward primarily from interest by the private sector. However, the TVA project has a $30 million commitment from the federal government. The Colorado-Ute and Northern States Power projects are being done with private funds. Colorado-Ute has made an application under the Clean Coal Technology solicitation. I believe that these and other clean coal technologies will move forward, driven by the private sector's interest in their development. However, the pace at which they move forward may not allow them to be developed in a timely manner to respond to any legislative initiative if one were to come to pass. Nor may many of the more risky technologies be implemented at all without federal assistance. The Clean Coal Technology Program and the federal involvement ensures that there will be a technological response adequate to respond to a need based upon environmental considerations if the environmental research shows that it is required.

Response #24

Yes, it is my opinion that life extension will in some instances delay the implementation of clean coal technologies. However, in many instances the availability of a commercially demonstrated technology will encourage the installation of that technology in many utility applications.

Response #25

If acid rain control legislation is enacted before the Clean Coal Technology Program has been implemented to allow for a sufficient number of technologies to be commercially demonstrated, then the costs for that legislation and the social impacts of unemployment and lost revenues in many localities will be unacceptably high. If, subsequent to developing a sufficient number of clean coal technologies, further controls on SO_2 and NO_x emissions are required, then the new technologies can mitigate the economic and social cost of further control. If emission reduction is mandated, then those emission reductions should be paid for as any other capital or operating expense that is incurred by the utility, and this is basically by the ratepayer in that local area.

Response #26

In my statement, we indicate that we believe there is little evidence to any widespread danger to aquatic or terrestrial resources at the present time. We would like to see the completion of the research that is investigating that, and we believe that this research will bear this fact out. However, over the long run, it will be in the nation's best interest as well as Peabody's best interest to find ways to burn coal more economically and more environmentally acceptably. The development of clean coal technologies provides the greatest potential for doing just that. That is why Peabody has invested its research dollars in developing these new technologies and trying to support the development of additional technologies.

TENNESSEE VALLEY AUTHORITY
KNOXVILLE TENNESSEE 37902

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JUL 2 1986

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
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WASHINGTON D.C. 20510

The Honorable James A. McClure
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

We appreciated the opportunity for Michael D. High to testify before your committee on June 10 on clean coal technology and acid rain control. We are enclosing 40 copies of TVA's responses to questions of committee members, as requested in your June 13 letter to Dr. High.

If we can provide additional information, please let us know.

Sincerely yours,

C. H. Dean, Jr.
Chairman

Enclosure

Question 1: EPA Administrator Thomas, on behalf of the Administration, stated that, "we do not yet believe that the current state of knowledge can sustain any judgement with respect to the level of emission reductions needed to prevent or eliminate damage." Do you agree with this statement?

We recognize that there are many gaps which make the current state of knowledge insufficient to precisely determine the level of reduction needed or to clearly define source/receptor relationships. Nevertheless, we believe the environmental risk is sufficient to warrant proceeding on the best information now available, if it can be done at a reasonable cost. Consequently, TVA supports acid rain control legislation that provides for equitable reductions from all sources, includes an emission-cap approach allowing cost-effective reduction measures, embraces the polluter-pays principle, and would be applied on a system-wide basis.

Question 2: EPA Administrator Thomas added, "this is true even for the area of greatest scientific understanding, sulfur emission and surface water acidification. In the area of the impact of acid deposition on forests, we have yet to determine if a cause and effect relationship exists." Do you agree with this assessment of current knowledge?

Surface waters and lakes exist in the northeastern United States and other parts of the world that no longer support desirable aquatic life due to high acidity. While acid deposition is expected by much of the scientific community to be a predominate contributor to this high acidity, the exact cause and quantitative relationship to sulfur emissions is still being defined. The impact of acid deposition on forest resources is more difficult to ascertain than the effects on water resources. However, TVA believes that the environmental risks are sufficiently well understood to support sizeable SO_2 and NO_x reductions.

Forest resources involve more complex processes and more time is required to evaluate chronic effects. Scientists have not yet determined a cause and effect relationship and the extent to which air pollution is a predisposing stress for forest impacts. However, the harm to sensitive species of trees and other vegetation from SO_2 at high concentrations is well known.

Question 3: On the basis of current knowledge of the causes of acid rain, in your judgement, can we formulate a control strategy that will assure achievement of the intended mitigation of acid rain once the prescribed control investments have been made?

In other words, can we determine what pollutants need to be controlled, the size reductions that are called for, where the reductions should take place, and over what timeframe they should be implemented?

A cause and effect relation is better understood between the precursors of acid rain—mainly SO_2 and NO_x—and the pH of rainfall than between acid rain and its environmental consequences. While the intended mitigation of acid rain (that is reducing the acidity of rain) can be assured with a reasonable degree of confidence, achieving a defined level of environmental benefit cannot be assured with the same confidence.

SO_2 and NO_x are the two acid forming pollutants which significantly contribute to the quantity of acid rain while hydrocarbons can effect the conversion of these pollutants to acids. However, with regard to forest effects, where the relative importance of other pollutants and factors is not well defined, ozone is believed to be at least as important as acid rain and therefore should not be overlooked. EPA is placing a higher priority on the ozone problem and many areas must reduce levels of hydrocarbon (a known ozone precursor) emissions.

We are not in a position to define a precise level of emission reduction to protect against quantifiable acid rain damage nor a specific timeframe for such reductions. However, in accordance with the principles outlined in response to question 1, we believe a reduction program should be implemented.

TVA's experience has been mainly limited to the Tennessee Valley region. We are, however, aware of the concern in the northeastern United States and Canada where certain areas are more susceptible to acid rain than the Tennessee Valley region and have experienced acidification of lakes. This, along with the recognition that acid rain is a regional and interregional concern and our assessment of risk discussed earlier, has lead us to concur

in a 31-State SO_2 control region as specified in earlier proposed legislation. A layer region would also be satisfactory. Much evidence exists that, while most of our sources' emissions impact an area relatively close to the pollution source, under certain meteorological conditions emissions can be transported for several days and therefore impact areas outside the region. Since this is a local, regional, and national problem, control measures should be addressed accordingly.

Question 4: There has been considerable discussion of the need to place emphasis on the development of clean coal technologies with retrofit application. For example, the Special Envoys' Report emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

EPA Administrator Thomas emphasized in his testimony that "the most important application category for the focus of clean coal technology development would be the coal-fired retrofit application." Do you agree?

a. In your judgement, does the DOE Clean Coal Technology program adequately reflect this need? Or does the program place too much priority on technologies applicable to new construction?

b. Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control? Should they be?

We agree that the primary focus of clean coal technology should be retrofit applications with emphasis on coal-fired systems.

a. The program guidelines provided to proposers did not specifically recommend "retrofit" applications over "new" applications. Of the 13 examples given for emerging clean coal technologies, less than half were generally applicable to retrofit cases. Since the vast majority of proposals received by the Department of Energy did relate to "new" applications, it is obvious that more emphasis could have been placed on the retrofit need.

b. In a broad sense, all the proposed Clean Coal Technology projects could be appropriate for acid rain control. For example, application of fuel cells could indirectly reduce SO_2 emission levels by forestalling the need to add more coal-fired generation capacity. However, if acid rain control legislation requires near-term decisionmaking (i.e., emission reductions in the early 1990s), some of the proposed technologies probably could not be applied since it could be many years before they would be commercially available.

New clean coal technologies should be developed to improve the overall environment. An appropriate mix of near-term and long-term technologies should be funded with more emphasis on retrofit.

Question 5: Under what circumstances will life-extension result in reduced atmospheric emissions?

The term "life-extension" is a recently coined phrase that is misleading in that it implies that it is a new concept and its only objective is to extend a plant's operating life. In reality, such programs have been in existence for a number of years and are designed to improve the performance and efficiency of existing facilities. These programs include improved maintenance, developing effective preventive maintenance programs, updating boiler controls, installing more efficient system components, and optimizing overall plant operations. Improvement in plant operating efficiency reduces the amount of coal required to obtain the same amount of generation and would, therefore, reduce the amount of SO_2 emitted on a per megawatt basis although the pounds SO2 per million Btu would remain the same.

For example, if a utility can improve the thermal efficiency of a 500-megawatt unit with an 11,000 Btu per kilowatthour heat rate by 10 percent (1,100 Btu per kilowatthour) with a 3.0 lb SO_2 per million Btu emission standard, then potential reductions of SO_2 emissions would be over 600 tons monthly (7,200 tons annually).

Additionally, life extension programs can include the utilization of emerging coal burning technologies as they become economically viable and could also include low NO_x burners. One noteworthy example is Wisconsin

Electric Company's plans to convert four 125-megawatt units to AFBC as an integral part of their life extension program. Since AFBC is a technology that is capable of meeting NSPS, this conversion should result in a significant reduction in SO_2 emissions and lower NO_x emissions.

Although AFBC is not a viable option for large boilers at the present time, as this and other coal-burning technologies are further developed and become economically competitive for large boilers, their utilization would be incorporated into future programs.

Question 6: What is the potential that the types of clean coal technologies under discussion will be able to meet New Source Performance Standards without the use of scrubbers?

Most of the clean coal technologies under discussion fall into two distinct categories—near-term/retrofit application and long-term/new application. Most near-term technologies—advanced coal cleaning, coal slurries, in-boiler control, and postcombustion cleaning—generally will not meet New Source Performance Standards without the use of scrubbers. An example of one that will is the atmospheric fluidized bed combustion process. The long-term technologies—gasification, magnetohydrodynamics (MHD), advanced combustors, and liquefaction—are more geared to meeting New Source Performance Standards without the use of scrubbers.

Question 7: Are the technologies being developed by the DOE Clean Coal Technology program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?

Most of the proposals submitted to DOE to date appear to be most applicable to new sources rather than for retrofit on existing sources. Such technology will be utilized by industry when building new plants to comply with New Source Performance Standards, and some of the technologies may also meet emission limitations that exist in some parts of the country. Furthermore, the development of low cost control technologies, which can reduce the cost of new source construction, is critical to accelerating the replacement of existing sources with better-controlled new sources. Therefore, no new regulatory requirements are needed to cause its deployment.

In the absence of new regulatory requirements, new control technology will also be deployed on existing sources if the new technology can be cost-effectively retrofitted to reduce the cost of compliance with existing control requirements. For example, the development of a lower cost FGD system, such as the spray dryer, may make it economical for an existing source now burning expensive low-sulfur coal to install the FGD system and comply while burning less expensive higher sulfur coal.

If new regulations were enacted which required final compliance within the next 10 years, it is doubtful that such regulations would have a major positive impact on the application of clean coal technology on existing sources. In fact, new requirements may actually inhibit such application. Because of the long leadtime required to design, procure, and install a pollution control system, utilities will have to commit to a control system four to five years in advance of the final compliance dates. In light of the potentially significant sanctions for failing to achieve compliance in a timely manner, utilities will want substantial certainty as to the viability of a control system before committing to it. This will provide additional motivation for utilities to continue to rely on more conventional, proven technologies to the detriment of possibly more cost-effective, environmentally beneficial control technologies. Thus, there would not be enough time for developing technologies to become commercially available.

There are, however, some technologies on the verge of becoming commercially available that could be introduced into the marketplace sooner with the enactment of new requirements. Atmospheric fluidized bed combustion (AFBC) technology is a good example of such a technology. Projects using AFBC technology are under development now, including a project at TVA's Shawnee Fossil Plant in western Kentucky. Three other utilities have already committed to installing AFBC boilers. Dry scrubbing, another promising technology which may become an economical option to burning low-sulfur coal, could also be brought into the marketplace sooner if new legislation were enacted.

Question 8: Mr. Donald Bauer, on behalf of DOE, stated that performance testing of clean coal technologies under consideration by DOE generally will not be completed until the early to mid-1990s. He concluded with the observation that "if the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options." Do you agree?

We agree with Mr. Bauer's assessment of the limited role new technologies would play in reducing emissions to comply with H.R. 4567 in the 1993-97 timeframe. TVA would depend primarily on the use of low-sulfur coal and conventional reduction technologies, such as wet-limestone scrubbers and low NO_x burners, to comply with H.R. 4567. Spray dryer technology, if demonstrated in the next few years, could also be considered as an alternative method of SO_2 control. If the timeframe of H.R. 4567 were more flexible, TVA would, of course, consider other technologies which were proven to be cost effective and reliable for both NO_x and SO_2 control. In addition, the Clean Coal Technology program may be able to provide new technologies to overcome constraints in taking emissions reductions at certain plants.

Controlling NO_x levels at cyclone boilers is an area where advancements in technology are needed if NOx reductions at existing plants are to be required by future regulations. The Electric Power Research Institute estimates that over 23,000 MW of cyclone boilers are in operation in the U.S., which is 13 percent of pre-NSPS coal-fired boilers. These boilers cannot be retrofitted with low NO_x burners. Available information suggests two possible alternatives to reducing NO_x emissions at these plants: converting the boilers to pulverized coal or fluidized bed units or installing some type of postcombustion NO_x control. Although not explored in detail, converting cyclone boilers to another boiler type would be a major undertaking involving unit outages of up to two years or more. Because of the large amount of generating capacity affected, these outages could cause power supply problems which could make this alternative infeasible. In addition, fluidized bed combustion on large capacity units has not been attempted, thus causing additional risks in this type of undertaking. Postcombustion technology such as selective catalytic reduction has been successfully demonstrated in Japan but there are no postcombustion NO_x removal systems in commercial operation on utility coal-fired boilers in this country. Thus, with technology currently available, reducing NO_x emissions from cyclone boilers may not be technically possible. However, this may be offset somewhat by applying low NO_x burners at most of the other coal-fired boilers.

Question 9: One of the premises behind the Clean Air Act was that industry would gradually retire old facilities and replace them with new installations subject to "new source performance standards." Consequently, there would be a gradual improvement in air quality. In your judgements has this occurred?

In asking this question it is observed that EPA Administrator Thomas, commenting on plant life extension trends, stated that, "this postpones the rate at which new sources will replace existing sources, making New Source Performance Standards a less effective way of reducing overall emissions in the near or middle term."

Industry's decision to retire facilities has historically been based on economics. This is evidenced by the fact that, of the approximately 500 fossil-fueled units retired through 1980, 90 percent have been below 50 megawatts in size; and the majority of those were below 25 megawatts. These units were built in the early 1900s and represented the first generation of improvements in plant efficiencies. By the early 1950s, plant designs had improved to the point that larger, more efficient units were being constructed; and these older, smaller units were becoming less competitive. Additionally, substantial load growth occurred between the 1950s and the mid-1970s, which forced utilities to greatly expand their systems to meet new demand. Since the leadtime required to build a new plant was also increasing due to environmental considerations and construction time, a significant number of plants were under construction at the time of the economic slowdown. As the plants continue to come online, utilities have the opportunity to retire their older, small, inefficient facilities.

Unfortunately, the technological advances made in the first half of this century that made it economically viable to replace existing generation with new generation have not continued as dramatically in the last 30 years. Therefore, the economic incentives for plant replacements have diminished, enhancing economic incentives for life extension. The lull in both load growth and technological development has resulted in additional life extensions.

It is entirely possible that the clean coal technology effort, if directed toward plant performance and combustion technology improvements, could provide plant efficiency improvements that would once again provide the economic incentives for industry to proceed with new generation rather than maintain existing facilities.

Question 10: In your opinions, what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the various legislative proposals before the Congress? For example, is the electric utility industry likely to rely on extension of the life of existing facilities rather than their retirement and replacement with new facilities?

TVA's strategy for meeting the various acid rain proposals has been based on meeting the provisions through a combination of coal switching and the addition of air pollution controls at our existing facilities. For TVA this approach is less costly than a strategy that would involve retiring units and replacing them with new facilities. Obviously, if an acid rain proposal restricts cool switching in order to protect the jobs of one group of miners, compliance costs could increase. Since strategy development involves many system specific considerations such as predicted load growth, plant age and condition, and generation mix, other systems may or may not have conditions that would lead them to this strategy.

Question 11: In your judgement, to what extent is industry's decision to extend the life of an existing facility influenced by regulatory policies? For example, as I understand EPA regulations, at a certain point the costs of retrofitting an existing facility become great enough that it runs the risk of being classified as a new one subject to New Source Performance Standards. Would you comment.

As stated in question 5, industry has historically been involved in programs to maximize the benefits of their investment through proper maintenance, equipment upgrading, and reliability improvement programs. The concept that a fossil-fueled unit can last beyond 30 to 40 years is not new. In fact, there are units still operating that are over 60 years old.

Although all existing plants will be retired at some point, that retirement will be based on the economics associated with continued operating costs including maintenance versus new construction.

Included in such a benefit cost study is operating cost, predicted load growth, new construction costs, and environmental costs related to regulatory policies. We believe that regulatory policies are not the deciding factor in such benefit cost studies to date.

Question 12: The Clean Air Act provides for an extension of compliance dates for facilities that propose to utilize new or innovative technologies to comply with emissions standards. In your judgement, has this authority been effectively implemented by the EPA?

TVA has not been faced with a compliance situation in which the additional time allowed by section 113(d) of the Clean Air Act for sources using new or innovative technology would be applicable. Accordingly, we have not had occasion to evaluate the effectiveness of these provisions.

Question 13: What is the national average cost of FGD retrofit per kilowatt? And, what would be the cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements? What would be the differential cost between implementation of the above options?

TVA has installed limestone scrubbers on four of its coal-fired units with a total generating capacity of 2,500,000 kW. The cost of these scrubbers, which were built in the 1974-83 timeframe, averaged $145 per kW. If built today, these scrubbers would cost considerably more due to inflation. TVA has not made detailed site-specific cost estimates for retrofitting scrubbers at the remaining plants on the TVA system. Rough estimates have been made, however, at plants where scrubbing would most likely be the preferred option for reducing SO_2 emissions. At these plants, TVA estimates the cost in 1986 dollars of retrofitting scrubbers would be approximately $230 per kW. Retrofit costs of scrubbers are very site specific depending on variables such as unit size, coal sulfur content, plant layout, and land availability for equipment placement and sludge disposal. In worst case situations, the cost of installing scrubbers could easily be in the range of $300 to $400 per kW.

Estimated capital cost of installing limestone scrubbers on the entire TVA system (excluding the cost of the scrubbers already built) would be about $3 billion. The annual cost of amortization, operation, and maintenance would be about $800 million (1986 $). On the other hand, TVA could reduce its present SO_2 emissions to approximately the same level by using a least cost combination of limestone scrubbers and low-sulfur coal for an annual cost of about $500 million (1986 $).

In general, scrubbers are the lower cost option at newer, more efficient plants which operate at base load and which are located in areas where low-sulfur coal is not readily available. At such plants, the high capital cost of scrubbers can be written off over a longer period and over the large number of kilowatthours that the plant produces. Low-sulfur coal becomes more economical for older plants which operate in an intermediate or peaking mode. Except for plants that must install new particulate control equipment to accommodate this coal, the entire cost of burning low-sulfur coal is a variable cost. At such plants, a relatively high premium can be paid for the coal before the high capital cost of scrubbers is offset. Even if capital expenditures must be made to install new particulate control equipment, low-sulfur coal is normally the most economical option because the cost of particulate control equipment is only about one-fourth the cost of scrubbers.

Question 14: What, in your judgement, are the estimated costs of implementing proposed acid rain legislation? Would you indicate the sources of such cost estimates and whether you agree, or disagree, with such analysis?

TVA has developed preliminary estimates of the cost of compliance with various acid rain control proposals for the TVA system but has not conducted any national cost estimates. Compliance with H.R. 4567 is estimated to cost TVA from 575 to 660 million dollars annually and would result in an average rate impact (commercial, industrial, and residential) of 12 to 14 percent. TVA's capital cost of control equipment to comply with H.R. 4567 is estimated to be $2 billion. Costs incurred by other utilities across the country could vary greatly depending on factors such as age of plants, current SO_2 emission rates, location with regard to low-sulfur coal fields, and types of generation (coal, hydro, oil, nuclear, etc.). For these reasons, TVA costs of reducing emissions may not be representative of costs that would be incurred by other utilities.

In contrast to the cost of H.R. 4567, TVA has estimated that it would have to reduce its emissions by 175,000 to 535,000 tons per year to achieve its share of a 10-million-ton national reduction goal at cost resulting in only a 2 to 4 percent rate impact. This assumes that reductions are allocated proportionately among all sources and that all cost-effective and enforceable control measures could be used.

Question 15: What, in your judgement, are the comparative roles of different source contributors of air pollution as contributing factors in acid precipitation? Would you indicate the sources of such information and whether you agree, or disagree, with such analysis?

The most reliable and extensive data base that is available to address this question is rain chemistry data from the U.S. rain network. These data show that rain acidity in the northeastern U.S. is dominated by sulfuric acid (60-70 percent on average), a smaller contribution from nitric acid (20-30 percent on average), and the remainder of the acidity associated with hydrochloric acid and weak organic acids.[1,2] Based primarily on these data, the control strategies to date have concentrated on sulfur dioxide sources (fossil fueled utilities, industrial boilers and smelters), and NO_x sources (transportation fossil-fueled utilities and industrial boilers).

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1. NRC 1983, Acid Deposition Atmospheric Processes in Eastern North America, National Academy Press, Washington, D.C.

2. EPA 1984, The Acid Deposition Phenomenon and its Effects Critical Assessment Review Papers - Vol. 1. Atmospheric Sciences EPA Report No. EPA-600/8-83-016AF

In considering their role in acid deposition, one must consider not only how much sulfuric and nitric acid is deposited, but also how the SO_2 and NOx that are emitted influence the chemistry that results in acid formation in the atmosphere. Acid production in the atmosphere is controlled by the concentrations of SO_2, NO_x, reactive hydrocarbons, and meteorological factors (sunlight, temperature, humidity, etc.). For example, controlling NO_x and reactive hydrocarbons can reduce sulfuric acid formation as well as reduce nitric acid levels in rain water.

Although there are still questions to be answered by further research, based on current knowledge, a strategy of reducing SO_2, NO_x, and hydrocarbons (a precursor to ozone) represents a reasonable scientific approach for mitigating acid deposition.

Question 16: An apparent problem for using clean coal technologies to mitigate acid rain is the timetables assumed to be required for reductions in SO_2 and NO_x. In your view, what is a reasonable timeframe for SO2 and NOx reduction? And secondly, which clean coal technologies are likely to be most readily available within that timeframe?

As more fully explained in response to questions 1 and 3, TVA believes the risk of continued deferring of control requirements may be greater than the economic risks of initiating a control program. Therefore, TVA does support a sound approach for mitigating the impacts of acid deposition even if it means initiating controls before innovative technologies are available. We believe a wide variety of retrofit technologies are ready for prototype evaluations or demonstration projects; thus, in five to eight years several of the innovative technologies could be available if work was aggressively begun now. Allowing for such development as a part of national acid rain control strategy would be desirable where the environment risks allow for such delays.

The two new technologies we have previously identified that TVA is helping to develop are AFBC and dry scrubbing. Others with promise of development within this timeframe might include advanced chemical and physical coal cleaning, precombustion controls, pressurized fluidized bed combustion, or advanced FGD systems such as dual alkali systems.

Question 17: In your view, is it realistic to expect emerging clean coal technologies to significantly contribute to SO_2 and NO_x reductions prior to the year 2000?

As discussed in the response to question 16, we suspect that several of the retrofit technologies could be available within approximately eight years. These then could be expected to contribute to SO_2 and NO_x reductions in the year 2000 timeframe. Less developed retrofit technologies and most of the technologies associated with new construction (with the exception of fluidized bed combustion) probably would have minimum impact on SO_2 and NO_x reductions by the year 2000.

Question 18: Having an interest in DOE's solicitation on clean coal technologies, do you believe tne range of projects currently reflects the best set of options for future clean coal applications?

The range of projects probably reflects the best set of options for future long-term clean coal applications. However, additional projects related to retrofit applications should be considered.

Question 19: Do you believe DOE's "payback" component of the solicitation has in any way dampened interest in proposing new technologies?

The payback provision of DOE's solicitation was regarded by many as being contrary to Congress' intent in establishing the Clean Coal Technology program. Though there was a substantial response to DOE's solicitation, it is difficult to determine the number and quality of projects that were not submitted or, without examining the actual responses, the number of exceptions taken as a result of the payback provision.

Question 20: In your statement, you suggest TVA's focus among clean coal technologies is on Spray Dryer Flue Gas Desulfurization (FGD) and atmospheric fluidized bed combustion (AFBC). What other clean coal technologies does TVA support?

TVA is currently focusing most of its control research attention on two technologies—spray dryer flue gas desulfurization and atmospheric fluidized bed combustion. We believe these two technologies offer the most promise of providing timely benefits to TVA and the Nation's power producing industry.

Currently, TVA is burning low-sulfur coal at the Shawnee Steam Plant to comply with the SO_2 emission standard. Shawnee is equipped with baghouse collectors, and spray dryers with these baghouses may allow us to burn higher sulfur coal to reduce compliance costs. A spray dryer pilot test yielding very favorable results has been completed and DOE has been approached for joint funding under the Clean Coal Technology program for a 160-MW spray dryer demonstration project.

Similarly, because of the numerous high efficiency precipitators at several of our plants, we are interested in the practicality of operating a spray dryer in conjunction with a precipitator. We are currently experimenting with a 1-MW unit and have a 10-MW unit under construction. Because of the wide use of precipitators nationwide for particulate control, this technology has widespread potential for application in reducing emissions.

TVA's interest in the AFBC is primarily for use as new or replacement capacity. AFBC could also be an alternative for NO_x emission controls as a replacement for cyclone boilers if legislation so required. TVA supports the clean efficient burning of coal nationwide and has therefore dedicated its research and development efforts to support the development of a wide variety of clean coal technologies. Past scrubber research efforts by TVA have included developments in forced oxidization, organic additives, dual alkali, magnesium additives, basic aluminumoxide scrubbing systems, research into mist eliminators, and many others. However, because of limited resources and projected power system requirements, we are currently focusing our research efforts on dry scrubbing and AFBC technologies. Other clean coal technologies may assume a higher priority within other power systems. As these technologies and advanced coal washing techniques are developed, we, of course, would evaluate the full spectrum of control options.

Question 21: Does TVA view clean coal technologies as a viable response to acid rain mitigation?

A. In the near term?
B. Longer term?

At the present time there are two major options available for reducing sulfur dioxide emission rates to low levels (≤ 1.2 lb/10^6 Btu) at most coal-fired power plants—the use of low-sulfur coal and limestone scrubbing. In the near term there are other options which have been shown to be technically feasible at the bench, pilot, and prototype levels but have not yet been shown to be economically competitive with limestone scrubbing through a full scale demonstration. If the Clean Coal Technology program is directed toward demonstrating such technologies over the next five to six years, one or more of them may become a viable option at some power plants for controlling SO_2 emissions. In addition, as discussed in question 7, AFBC technology, which will complete its demonstration phase at TVA's Shawnee plant in the early 1990s, may also have retrofit application in some circumstances.

In the longer term, clean coal technology research and demonstration are critical in the development of more economical and efficient options for using coal to produce electric power in an environmentally acceptable manner.

Several of the control technologies covered by the clean coal technology could also result in reduced NO_x emissions. Those technologies would include fluidized bed combustion, gasification, advanced combustion, liquefaction, and possibly others. DOE's clean coal technology also has provision for research on postcombustion cleanup which could include research on NO_x scrubbers.

While many conventional boilers can be retrofitted with low NO_x burners, others such as cyclone boilers cannot. Acid rain control legislation requiring NO_x controls on cyclone boilers would create a significant need for developing new NO_x controls. Currently postcombustion NO_x controls have been used only with coals with low sulfur and ash content. Such coals cannot be used in cyclone boilers because of ash fusion problems, thus likely making this control equipment incompatible with cyclone boilers.

Question 22: You state that AFBC technology has not been built on a scale sufficient to assure commercialization, but that EPRI in conjunction with utilities are building "utility-sized" demonstration units. Given current production, how cost effective are these conceptual units supposed to be for retrofit applications?

A. Since there is a ten-year cycle for data acquisition planned, is this technology a reasonable response to acid rain mitigation?

Retrofit costs are heavily site dependent. The true cost effectiveness of AFBC retrofits comes in conjunction with projects where the boiler can be upgraded and emissions can be reduced with the same capital expenditure. Operating costs will not be verified until the demonstration units have been brought into service. These costs are forecast to be 10- to 20-percent lower than conventional pulverized coal with wet scrubbers but still significantly more expensive than retrofitting scrubbers.

By 1990, nearly 1000 MW of AFBC capacity will have been brought online. Successful demonstration will answer important questions that remain about scaleup, operation, and economics. Although the full test and commercial demonstration schedules extend for 10 years, enough will have been learned in the first few years to allow proceeding with 100- to 350-MW retrofits with minimal risk. Since retrofits can be accomplished in two to four years, the technology will be a reasonable option for utilities to bring online by the middle-to-late 1990s.

Responses of David G. Hawkins to questions submitted
by Senate Committee on Energy and Natural Resources:
Hearing on Clean-Coal Technology and Acid Rain

Question 1. EPA Administrator Thomas, on behalf of the Administration, stated that,

> "we do not yet believe that the current state of knowledge can sustain any judgement with respect to the level of emission reductions needed to prevent or eliminate damage."

Do you agree with this statement?

Answer:

I disagree. The current state of knowledge establishes that emission reductions beyond those now mandated by the Clean Air Act and EPA's regulations are necessary to prevent damage that is now occurring. The current state of knowledge also is adequate to support a conclusion that significant emission reductions from today's levels will produce substantial benefits to those resources now at risk due to acid deposition and its precursor pollutants. This judgement has been articulated by numerous independent scientific experts and is reflected in four reports of the National Academy of Sciences issued since 1981. This judgement is also reflected in the reports of the Expert Meetings on Acidification of the Environment issued in Stockholm in June 1982. EPA scientists attended the Expert Meetings and joined in the reports' findings.

The above reports and others, including EPA studies, establish that current atmospheric loadings of sulfur dioxides and nitrogen dioxides are responsible for surface water acidification, impairment of visibility, and damage to man-made structures and other materials. The current state of knowledge supports the judgment that damages to these resources will be significantly reduced if emissions of these pollutants are significantly reduced. In addition, these pollutants present risks to crops, forests and human health. Emission reductions also will reduce this latter group of risks.

The Administrator's statement appears to argue that there is some level of uncertainty with respect to the precise level of reduction in atmospheric deposition that is "needed to prevent or eliminate damage" and to the precise level of emission reductions needed to reach such a target for deposition. There is, of course, some uncertainty with respect to these levels just as there is such uncertainty for every environmental standard EPA has ever issued or ever will issue. The Administrator's statement elevates this small uncertainty above all other considerations, implying that the country will be "better off" if control action is delayed and the status quo continued.

However, the reports cited above establishe that significant damages to natural and man-made resources will continue under the status quo and that such damages will be substantially reduced or prevented for identifiable classes of resources with the emission reduction programs contained in several proposed "acid rain control" bills. The small uncertainty at the margin regarding the precise level of resource protection that is achieved by any specific emissions reduction program cannot justify further delay in enactment of a control program by Congress.

The Administrator's statement appears to argue that action now by Congress carries risks that we may control "too much" or "too little." This claim is not defensible. All objective analyses show that any such risks pale in comparison with the threats that we know we are imposing today on valued resources in the absence of a control program.

As Administrator Thomas himself has recently recognized, in the context of ozone pollution, uncertainties about achieving ultimate protection objectives should not be accepted as a reason to avoid or delay action on those control programs that are possible to implement and that we know will significantly improve the current situation:

> "If we reduce ozone concentrations incrementally, we will reduce the risk to human health incrementally. That will be an important achievement in itself, even when the standard is not obtained. For those reasons, we need to make decisions about further control actions and these decisions must be made in the context of a comprehensive national strategy." (From remarks of Lee M. Thomas before the Air Pollution Control Association, June 23, 1986.)

Question 2. EPA Administrator Thomas added,

> "this is true even for the area of greatest scientific understanding, sulfur emission and surface water acidification. In the area of the impact of acid deposition on forests, we have yet to determine if a cause and effect relationship exists."

Do you agree with this assessment of current knowledge?

Answer:

Insofar as Administrator Thomas' statement relates to surface water acification, I have addressed this point in my response to question No. 1. With respect to his discussion of forest impacts, there is general agreement that the uncertainty regarding the causes of forest damage is greater than the uncertainty regarding other types of damage discussed above. I believe there is scientific consensus on several points regarding forest damage. First, significant damage is occurring in eastern North America with symptoms that in many respects parallel those observed in the early stages of forest deterioration now thoroughly documented in West Germany. Second, it is highly probable (and, in the view of some scientists, certain) that air pollution is the main controllable contributing factor to this forest decline, although the contribution of other factors has not been ruled out. Third, empirical studies continue to support the hypothesis that nutrient imbalance and acidification effects caused by acid rain precursor emissions are the major contributors to forest decline. Recent studies in West Germany indicate that sulfur dioxide and ozone concentrations interact synergistically to cause damage, supporting the view that reductions in sulfur dioxide emissions will be an effective strategy for reducing forest damage.

Whatever one's opinion of the degree of uncertainty associated with the forest damage issue, that controversy should not be allowed to mask the fact that there is virtually no uncertainty with respect to the cause and effect relationship between sulfur dioxide emissions and damages due to surface water acidification, visibility impairment and damage to materials. The documented damages to these resources alone warrant a control program. The fact that forests in addition will most probably be benefited by a reduction in acid rain precursor emissions is an important additional reason for going forward with such a control program.

Question 3. On the basis of current knowledge of the causes of acid rain, in your judgement, can we formulate a control strategy that will assure achievement of the intended mitigation of acid rain once the prescribed control investments have been made? In other words, can we determine what pollutants need to be controlled, the size reductions that are called for, where the reductions should take place, and over what time frame they should be implemented?

Answer:

Yes. See answers to questions 1 and 2.

Question 4. There has been considerable discussion of the need to place emphasis on the development of clean coal technologies with retrofit application. For example, the Special Envoys Report emphasizes that preference should be given to demonstration projects for retrofit control of existing sources.

EPA Administrator Thomas emphasized in his testimony that "the most important application category for the focus of clean coal technology development would be the coal-fired retrofit application." Do you agree?

a. In your judgement, does the DOE Clean Coal Technology program adequately reflect this need? Or does the program place too much priority on technologies applicable to new construction?

b. Are all clean coal technologies potentially funded by the DOE program likely to be appropriate for acid rain control? Should they be?

Answer 4a

I do not agree that retrofit of existing coal-fired power plants should be the focus of the national "clean coal technology" development program. As I indicated in my testimony, the current mix of technologies for reducing sulfur dioxide emissions is adequate to support a significant, economically affordable program to reduce these emissions from existing power plants. In addition to already demonstrated technologies, there are a small number of additional technologies, suitable for retrofit application, that have progressed to the point where they can be demonstrated on commercial scale without additional delay. I believe that such commercial demonstrations are useful and should proceed.

However, in my opinion, the greater potential of the clean coal technology program lies in the development over the medium-to long-term of technologies that apply to new sources and to sources making major life extension investments. The current attempt by some opponents of acid rain control programs to portray the clean coal technology program as a major contributor to a solution to the problem of acid rain is misguided and does not serve the interests of clean coal technology development. If the focus of the clean coal technology program is directed primarily at making marginal improvements in near-term control options available for retrofit applications, the program will necessarily give less attention to the new source and life extension categories. If the success of the clean coal technology program begins to be defined in terms of major new advances for the retrofit sector, I believe the most likely outcome is that the program will be judged a failure. This could result in the clean coal technology program losing political support and being abandoned without its ever having pursued the targets of greater opportunity in the new source and life extension market.

Answer 4b

As I indicated in my testimony, only a few of the 51 proposals submitted to DOE have any potential usefulness in an acid rain control program. The public abstracts for these few projects state that results will be available by about 1990. Thus, if the results are positive, they will be usable under currently proposed legislative timetables.

Question 5. Under what circumstances will life-extension result in reduced atmospheric emissions?

Answer:

Under the current Clean Air Act and EPA regulations, life extension programs will not result in reduced emissions. By definition, life extension programs are a substitute for the construction of new capacity. Under the Clean Air Act, such new capacity is subject to the new source performance standards (NSPS), which require fairly stringent control of SO_2 and particulate emissions. If that capacity need is met instead by extending the life of the existing plant, all such life extension projects will increase emissions over what would occur if new capacity were built, since there are no current regulatory requirements (nor economic incentives) for life-extension plants to reduce emissions to NSPS levels.

Question 6. What is the potential that the types of clean coal technologies under discussion will be able to meet New Source Performance Standards without the use of scrubbers?

Answer:

There is significant potential for emerging clean coal techologies that are principally applicable to the new source market to meet new source performance standards without the use of scrubbers. This is clearly the case for combined cycle coal gasification, for example. In addition, data collected by EPA in support of its recently proposed new source performance standards for industrial power plants demonstrates that atmospheric fluidized bed combustion systems can also meet the requirements of the 1979 utility boiler NSPS without the use of scrubbers.

Question 7. Are the technologies being deveoped by the DOE clean coal technology program likely to be utilized absent new regulatory requirements, or are new regulatory requirements going to be necessary for their deployment?

Answer:

I believe that new regulatory requirements are essential to provide an incentive for the application of any technologies, emerging or conventional, whose principal purpose is to reduce emissions below current requirements at existing plants. Life-extension candidates are a major potential market for emerging technologies, but only if emission control requirements for existing plants are strengthened. As long as existing plants enjoy lenient emission limits and are permanently "grandfathered" from new source performance standards (NSPS), there will be no incentive for life-extension projects to choose technologies that reduce emissions. Regarding new plants, use of emerging technologies will depend on the relative economics of those technologies compared to the leading current conventional approach: an FGD-equipped pulverized coal-fired boiler.

Question 8. Mr. Donald Bauer, on behalf of DOE, stated that performance testing of clean coal technologies under consideration by DOE generally will not be completed until the early to mid-1990s. He concluded with the observation that "if the timetable established in H.R. 4567 becomes law, the nation's utilities and industries would likely be locked into conventional technology and the economic and performance penalties inherent in today's limited set of technological options." Do you agree?

Answer:

I disagree.

First, I disagree with the premise of Mr. Bauer's statement, that today's technological options have significant "economic and performance penalities." As stated in my testimony, today's technologies include several types of highly developed flue gas desulfurization (FGD) systems, coal cleaning methods and fuel switching. Together, these emission control methods provide proven and effective means of accomplishing a major reduction in sulfur dioxide emissions. To the extent that Congress wishes to place some restrictions on fuel switching, this can be done to a greater or lesser degree without preventing the accomplishment of an affordable emission reduction program. As mentioned in my testimony, West Germany is implementing today a major control program that relies heavily on the use of FGD systems.

Second, Mr. Bauer's claim that the timetables in H.R. 4567 would not permit use of any emerging technologies, is not correct. Under H.R 4567, sources will not need to begin construction of equipment to meet the bill's first phase reductions until about 1991. By this date, there will be long-term operating results from potentially attractive retrofit technologies such as furnace sorbent injection and duct sorbent injection systems. The current Clean Coal Technology program selections announced July 25, 1986, would fund such projects at four midwestern facilities, with commercial operation beginning prior to 1990.

Question 9. One of the premises behind the Clean Air Act was that industry would gradually retire old facilities and replace them with new installations subject to "new source performance standards." Consequently, there would be a gradual improvement in air quality. In your judgements, has this occurred?

In asking this question it is observed that EPA Administrator Thomas, commenting on plant life extension trends, stated that, "this postpones the rate at which new sources will replace existing sources, making New Source Performance Standards a less effective way of reducing overall emissions in the near or middle term."

Answer:

I agree that it was the intent of Congress in 1970 to reduce emission loadings nationally by requiring new sources to meet stringent control requirements. However, utilities are not retiring existing poorly controlled units at the end of what has historically been regarded as their useful life, 30-35 years. Nearly all large generating units built since the 1950s are still in operation and are expected to continue in operation for lives of 60 years or more. Because under EPA's current rule a source can extend its life indefinitely, provided its life-extension does not exceed 50% of the unit's replacement cost, these existing sources enjoy permanent immunity from further control.

This permanent "grandfather" status has largely prevented the emission reductions intended by Congress from occurring.

Question 10. In your opinions, what is likely to be industry's approach to meeting the new acid rain regulatory requirements under the various legislative proposals before the Congress? For example, is the electric utility industry likely to rely on extension of the life of existing facilities rather than their retirement and replacement with new facilities?

Answer:

Industry is likely to rely on both retirement of existing units and application of controls to existing units. Given the large population of existing plants with long remaining lives and the high cost of new plants, it is reasonable to expect that most emission reductions will come from controlling existing plants as opposed to retirements.

Question 11. In your judgement, to what extent is industry's decision to extend the life of an existing facility influenced by regulatory policies? For example, as I understand EPA regulations, at a certain point the costs of retrofitting an existing facility become great enough that it runs the risk of being classified as a new one subject to New Source Performance Standards. Would you comment.

Answer:

In my opinion, the most important factor causing owners to extend existing plant life rather than replace plants is the high cost of such replacements relative to life-extension costs. Since, as noted above, EPA's new source performance standards (NSPS) become applicable to life-extension units only when expenditures exceed 50% of replacement costs, potential applicability of NSPS rules appears to affect the type of life-extension investments rather than determine whether life-extension investments will be made. Current new plant capital costs range from $1100-1600 per kilowatt, while many life-extension projects are estimated to cost between $300-500 per kilowatt. Note that even if there were no NSPS costs associated with a new plant (typically $250-450 per kilowatt), it would still be less expensive to extend the life of an existing plant as long as pollution controls are not required to be upgraded.

However, permitting plants to extend their lives without reducing emissions discourages use of clean coal technologies like fluidized bed combustion (FBC) in life-extension projects. Technologies like FBC have lower emissions but are more expensive than simply refurbishing an existing conventional boiler. Since, under current rules, sources can extend boiler lifetimes without reducing emissions, there is a bias against investing in cleaner technologies like FBC.

Question 12. The Clean Air Act provides for an extension of compliance dates for facilities that propose to utilize new or innovative technologies to comply with emissions standards. In your judgement, has this authority been effectively implemented by the EPA?

Answer:

This authority, in my opinion, is not a very powerful incentive for innovation, absent market or other regulatory incentives (such as more stringent emission control requirements) for developing innovative control methods. While there are undoubtedly improvements to EPA's program that could be identified, it is not clear that any such improvements would result in greater innovation activity.

Question 13. What is the national average cost of FGD retrofit per kilowatt? And, what would be the cost of retrofit of all existing facilities to meet scrubber technologies rather than emission specific requirements? What would be the differential cost between implementation of the above options?

Answer:

PEDCO reports that the average cost of all flue gas desulfurization (FGD) systems operating at the end of 1983 was $109 per kilowatt. (See reference 1 in Attachment 1 to my testimony.) New plant FGD system costs range from an average of $148 per kilowatt for one FGD vendor to $177 per kilowatt estimated by EPRI, both in 1984 dollars. (See Attachment 1 to my testimony at 6.) Regarding the cost of installing retrofit FGD systems on all existing units, I am not aware of any proposal that would require universal FGD retrofit of U.S. units, nor am I aware of any estimate of the costs of such a program.*/ As I mentioned in my testimony, West Germany is undertaking such a program for all large units that intend to operate past 1993. Such FGD systems are being installed now, so that the information is currently available to permit an analysis of the "real-world" costs of such a program. However, no such analysis of the German program has been prepared.

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*/ Sen. Stafford's bill, S. 2203, requires all units to meet a specific emission limit or retire. In addition, the bill provides that existing units' "grandfather" status under the NSPS program ends after 35 years of operation. The Congressional Budget Office has recently estimated the cost of S. 2203 at $8.8 billion per year. As discussed below, CBO's estimates, in my opinion, significantly overstate the costs of S. 2203 and other (continued next page)

The Congressional Budget Office (CBO) has recently published an estimate of the projected cost differences between a program that permits unlimited fuel switching and one that requires sources to continue using 1985 fuel supplies for 80% of their needs. Given CBO's assumptions, this approximates an FGD-mandate program versus a "free-choice" program. CBO estimates annual costs for a 10-million-ton reduction program to be $3.25 billion under the "free-choice" option and $4.73 billion under the "FGD option." In my opinion, the CBO study overstates the costs of both options, with a greater overstatement for the "FGD option."

First, the study assumes that retrofit FGD systems will be 90%-control, full-gas-stream systems, with spare modules. (Study at 147.) This would not be the most efficient FGD-retrofit program. Under a 10-million-ton reduction program with fuel switching restricted, most units will not have to treat all of their gas stream in order to meet their required emission reduction. Applying an FGD to only a portion of the flue gas stream results in substantial cost savings. (See Attachment 1 to my testimony at 6-7). Moreover, spare modules will not be

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programs where significant FGD retrofit is assumed.

required under proposed acid rain bills because the FGD system can be bypassed during upsets or maintenance, as long as the overall annual emission reduction required by the bills is met.

Second, the CBO study assumes a "retrofit penalty" of $125 per kilowatt for every retrofit FGD system. (Study at 147). The CBO retrofit penalty is several times greater than that assumed in EPA and other studies, and CBO does not document its basis. As mentioned above, for the case examined by CBO, it is very likely that units would choose partial gas stream treatment, so that little if any retrofit penalty would occur, due to the reduced space, duct, fan, and pump requirements of partial systems.

Third, the National Coal Model employed in the CBO study is believed to be based on fairly "steep" supply curves for coal production. (Large price increases per unit of production increase are assumed.) In recent years, analysts have questioned the validity of relying on conservatively defined coal reserve data to develop coal supply curves, arguing that, as demand increases, less-documented reserves will be used for production, at costs below those assumed for current reserves. (See generally the documentation for the coal supply module of EPA's Advanced Utility Simulation Model.)

Question 14. What, in your judgement, are the estimated costs of implementing proposed acid rain legislation? Would you indicate the sources of such cost estimates and whether you agree, or disagree, with such analysis?

Answer:

A large number of different cost studies for different acid rain control bills have been prepared over the last six years for EPA, DOE, the utility industry, the high- and low-sulfur coal producers, the environmental community and the Congress. Results of the earlier of these studies have been summarized in "Acid Rain: A Technical Inquiry" (Comm. Print No. 97-H53, Sen. Comm. on Env. and Pub. Works) and in "Acid Rain and Transported Air Pollutants" (Office of Technology Assessment, June 1984). Most of these studies report annualized costs of $300-600 per ton of sulfur dioxide reduced (or $3-6 billion annually for a 10-million-ton reduction). In my opinion, these are conservative cost estimates (i.e., probably overestimates), due to high FGD cost assumptions, coal supply assumptions and failure to consider the potential for use of furnace and duct sorbent injection systems.

Question 15. What in your judgement, are the comparative roles of different source contributors of air pollution as contributing factors in acid precipitation? Would you indicate the sources of such information and whether you agree, or disagree, with such analysis?

Answer:

The most important pollutant to control solely for protection of aquatic resources is sulfur dioxide (SO_2). Control of nitrogen oxide NO_x is also warranted for aquatic resource protection. However, per ton emitted SO_2 poses a greater threat to aquatic resources due to the mitigating effect of vegetative uptake of NO_x deposition. To protect against visibility impairment, control of both these pollutants, as well as hydrocarbon control is required. To protect against materials damage, control of SO_2 is required. To reduce risks to crops and forests, control of SO_2, NO_x, and hydrocarbons is warranted. To reduce documented harm to health from ozone and health risks due to sulfate exposure, control of these three pollutants is also necessary.

In sum, a program to reduce emissions of SO_2, NO_x, and hydrocarbons is required to reduce the ecological, economic and human health problems associated with the transport and deposition of these pollutants, a phenomenon popularly termed "acid rain." The most useful references for a discussion of these effects include the four National Academy of Sciences reports released since 1981, the June 1984 Office of Technology Assessment study referred to above, the June 1982 Technical

Experts report of the Stockholm Conference on Acidification of the Environment, and EPA's Critical Assessment Review Papers.

Question 16. An apparent problem for using clean coal technologies to mitigate acid rain is the timetables assumed to be required for reductions in SO_2 and NO_x. In your view what is a reasonable timeframe for SO_2 and NO_x reduction? And secondly, which clean coal technologies are likely to be most readily available within that timeframe?

Answer:

I believe that from a technical, economic, and environmental perspective it is reasonable to begin a major reduction program immediately. As indicated in my testimony, the gains potentially available from a "clean coal technology" program are not large enough to warrant any delay in the implementation of such a reduction program. Moreover, to the extent a program is implemented on the timetable contained in H.R. 4567, there will be adequate time to decide whether to use those emerging technologies now scheduled for commercial demonstration. See answer to question 8.

Question 17. In your view, is it realistic to expect emerging clean coal technologies to significantly contribute to SO_2 and NO_x reductions prior to the year 2000?

Answer:

In the absence of a new program requiring major emission reductions well before the year 2000, it is certain that emerging technologies will not be used to produce significant emission reductions. A new control program cannot guarantee that such emerging technologies will be used, for such use will depend on the relative costs of such technologies and the willingness of utility operators to choose "first-generation" emerging technologies, no matter how fully demonstrated, over third- and fourth-generation FGD and coal cleaning systems.

Question 18. Having an interest in DOE's solicitation on clean coal technologies, do you believe the range of projects currently reflects the best set of options for future clean coal applications?

Answer:

As discussed in my testimony, the proposals submitted in response to the DOE clean coal technology solicitation do not contain a large number of different technologies suitable for retrofit application. Whether this is an appropriate situation depends on one's view of the purpose of a "clean coal" program. In my opinion, the major potential of such a program lies in the exploration of ways to reduce the impacts of coal energy use over the long term, principally in new source applications, rather than in an attempt to provide a significant near-term expansion of control options for existing plants. See answer to question 4a.

Question 19. Do you believe DOE's "payback" component of the solicitation has in any way dampened interest in proposing new technologies?

Answer:

This has been claimed. However, I have no basis for an independent assessment of this claim.

Question 20. In your prepared remarks, you suggest the "traditionally conservative engineering approach of the (utility) industry" may have slowed down the demonstration of clean coal technologies at the 100 mw level or greater. Would you comment on this statement?

Answer:

Utility managers have tended to be understandably conservative regarding the risks of applying new technologies, due to the scale of utility operations, the large consequences of failure, and the rewards permitted under a regulated system. First, as to scale, commercial demonstration of a new utility technology typically involves very large amounts of capital relative to other industrial applications due to the very large size of current utility generating units. Second, risks of failure include not only the costs of writing off the capital investment for the "innovative" technology, but also the potentially large costs of purchasing power to make up for generating losses at the unit using the innovative technology. Third, given the regulated rate-of-return structure of the utility industry, it appears that, in contrast to unregulated firms, the financial rewards of a successful innovation are not often large enough to compensate for the risks of relying on newer technologies.

Question 21. Your testimony indicates you agree with the majority of our witnesses that clean coal technologies are no panacea for resolving our concerns over acid rain. In your view, what is a reasonable timetable for implementation of clean coal technologies as a mitigant for acid rain?

Answer:

See answer to question 16.

Question 22. Do you feel the DOE solicitation of proposals effectively empasses the universe of viable clean coal technologies?

Answer:

See answers to questions 4a and 18.

Question 23. What effect, in your view, has the DOE repayment scenario had on the submission of clean coal proposals?

Answer:

See answer to question 19.

Question 24. Is NRDC concerned about the apparent focus of the proposals on long-term solutions, rather than on retrofit technologies?

Answer:

See answers to questions 4a and 18.

Question 25. In your view, which clean coal technology is most promising as a mitigant for SO_2 and NO_x?

Answer:

In my view, furnace and duct sorbent injection systems would be a useful complement to the existing mix of controls and are capable of being successfully demonstrated in a 2-3 year time frame, given adequate incentives. See answer to question 8.

Question 26. Apparently NRDC supports the emission-specific approach to acid rain mitigation. Doesn't this force utilities into the untenable position of choosing between existing scrubber technology, and longer-term, more efficient clean coal technologies?

Answer:

Any program requiring near-term emission reductions will require utilities to choose between retiring existing boilers, applying conventional controls to such boilers, or applying emerging controls to such boilers. As I indicated in my testimony and in answer to questions 7, 8, and 16-18 above, in my opinion, current conventional controls form a sound basis for a major emissions reduction program, with emerging technologies occupying a small niche that utilities may not choose to pursue, no matter how rapid or slow the timetable for emission controls.

Question 27. In the long run, will it not be in the utilities' best interest to retrofit, repower, extend and build new sources with some form of clean coal technology?

Answer:

Adoption of an acid rain control program, including a limitation on the number of years that existing sources are "grandfathered" from the NSPS program, will expand the medium- and long-term markets for clean coal technologies like fluidized bed combustion (FBC) and combined cycle gasification (ICCG). Without additional emission control programs, utilities will rely more on boiler refurbishment to help meet future capacity needs than on repowering with FBC or ICCG. The latter technologies are more expensive than refurbishment and, in the absence of additional emission control requirements, the fact that they result in lower emissions will be unimportant to utility decisionmakers. However, adopting more stringent controls for existing sources, as is proposed, for example, in S. 2203, will increase incentives to replace existing boilers (either in repowering situations or new unit applications) with newer technologies like FBC or ICCG.

Question 28. Virtually all other witnesses suggest that the timeframes outlined in H.R. 4567 are economically unrealistic given existing technology, both retrofit and new technology. On what basis does NRDC project success with this approach?

Answer:

See my testimony and attachments generally, as well as the answers to questions 7, 8, and 16-18 above.

APPENDIX III

ADDITIONAL MATERIAL SUBMITTED FOR THE RECORD

STATEMENT OF THE
AMERICAN GAS ASSOCIATION
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
ON CLEAN COAL TECHNOLOGIES AND ACID RAIN
June 9, 1986

The American Gas Association (A.G.A.) is pleased to submit its views on acid rain and how the Department of Energy's Clean Coal Technology Fund would assist in controlling acid rain. A.G.A. is a national trade association composed of nearly 300 natural gas distribution and transmission companies. Together, these companies account for nearly 85 percent of all gas utility sales.

STATEMENT OF POSITION

Natural gas is the cleanest burning fossil fuel. It emits virtually no sulfur oxides or particulate matter, and fewer nitrogen oxides than any other fossil fuel. Thus, burning some natural gas with, or in place of, coal can reduce sulfur oxide air pollutants just as cost-effectively as flue gas desulfurization or scrubbers, for a fraction of the cost. Although acid rain and environmental protection are now major public policy goals, the costs of environmental compliance continue to escalate. Thus, any acid rain proposals must permit plant operators to choose the most cost-effective compliance alternative for each site.

One of the first steps that Congress can take to reduce future pollution is to repeal the uneconomic prohibitions on natural gas use: in some Department of Defense Appropriations bills;[1] in the incremental pricing provisions of the Natural Gas Policy Act;[2] and in the Powerplant and Industrial Fuel Use Act (FUA).[3]

---

[1] Since these restrictions force U.S. military facilities to use more polluting fuels, they will make it much more difficult for individual states to achieve SOx and NOx reductions. A recent National Defense Council Foundation Report, Congressionally Mandated Energy Waste at the Department of Defense (February 1986), found that special interest legislation is forcing the Department of Defense to use coal or oil in many facilities despite cheaper energy alternatives. Over time, these restrictions will cost the American people from $2.1 billion to as much as $5 billion.

[2] Incremental pricing (15 U.S.C. §3301 *et seq*.) requires industrial boiler owners to pay a surcharge for their natural gas. Although this surcharge originally was intended to shield residential gas consumers from higher prices, actually it hurts all consumers because it makes natural gas non-competitive with high sulfur residual oil in some regions of the country. This not only causes load loss and higher residential gas rates, but also has a detrimental effect on air quality.

[3] FUA (42 U.S.C. §8301) is a particularly wasteful and environmentally detrimental statute which prohibits the construction of new natural gas-fired large industrial boilers or electric power plants. It even prohibits the construction of combined-cycle power plants, one of the cheapest and most energy efficient ways to generate electricity. A research paper by the Urban Institute, Regulatory Restraints on Natural Gas Use: The Logic Is Lacking (October 1985), estimates that by restricting plant operators to coal, FUA will result in substantial additional pollution: 2 billion pounds of SOx between now and the year 2000, plus 600 million pounds of NOx, and over 100 billion pounds of extra sludge and ash that

We urge you to support the repeal of restrictions on natural gas consumption.

DOE CLEAN COAL PROGRAM

Projects funded by the Department of Energy (DOE) Clean Coal Technology Fund will have no immediate impact on reducing acid rain. Congress created the Clean Coal Fund to finance "emerging clean coal technologies" and accelerate the commercial availability of these technologies. Accordingly, research proposals were submitted to DOE seeking funding in technologies areas such as surface coal gasification, fuel cells, flue gas cleanup and underground coal gasification. In its description of the proposals, DOE stated that these technologies are not expected to become commercially available before 1990. Therefore, assuming that all of these clean coal technologies will be successful, they would not be available for at least four to ten years. In contrast, it appears that most of the acid rain proposals contemplate retrofitting coal-fired powerplants in a much shorter period of time.

FOOTNOTE CONTINUED

3/ must be disposed of safely. The Urban Institute said that repealing FUA would "reduce the annual cost of producing electricity and energy-intensive industrial goods by $1.65 billion (measured in constant 1985 dollars). The present value of the savings between 1986 and 2000 would be about $5 billion."

NEW TECHNOLOGIES
Using Natural Gas For Cleaner Coal And High-Efficiency Power Generation

There are many different clean air technologies; some of them use mechanical systems to remove pollutants while others use clean burning natural gas. The natural gas technologies include:

(1) for existing facilities, the select use of gas to offset emissions from coal or high sulfur oil;

(2) for new facilities, low emitting cogeneration and combined cycle units that will reduce the rate of increase in pollution from new facilities; and,

(3) for new and existing facilities, reburn technology which reduces NOx emissions from coal.

1). Select Gas Use

"Select Use" is a relatively new but well proven combustion technique: burning natural gas with less environmentally attractive fuels in the same or a separate boiler for environmental purposes. Gas can be used with Eastern high sulfur or Western low sulfur coal and with residual fuel oil. In one option, gas may be burned in a fuel mixture, usually with coal, in the same unit.

Similar applications, called "bubbles" when approved by the Environmental Protection Agency, would be particularly useful and cost-effective. Converting just a few facilities in a given state to SOx-free natural gas could save the costs of installing scrubbers on numerous plants throughout the State. For example, the state of Wisconsin recently enacted acid rain legislation which focuses on the 43 largest emitters of SO_2 in the State. Of these sites, at least 16 are already hooked up to gas and could use gas to reduce SO_2 emissions immediately by 50 percent, for a total statewide reduction of 134,000 tons of SO_2/year.

Select use technology has already advanced from the theoretical to the actual. Many select use applications have been approved by EPA and implemented. About one-third of them, to date, involve the use of natural gas. As an example, the St. Joseph Resources zinc plant in Palter Township, Pennsylvania, will begin co-firing gas with coal in 1987 to meet its sulfur emission limits under an EPA consent decree. Some of the advantages of select use are that:

- Plant Operators Could Realize Lower Costs. Using natural gas to offset SOx emissions from coal units tends to have low capital requirements. In many cases, this strategy has the lowest total costs of any control option. The costs of SO_2 reductions by using natural gas with coal have been calculated to vary from a very low \$50/ton of SO_2 reduced to over \$1000/ton, with many applications in the \$200-\$400/ton range. By comparison ICF, Inc., an independent consultant, estimates a range of costs, from \$250 to \$2000/ton of SO_2 removed, for seven straight coal alternatives. Thus, natural gas/coal strategies are at the low end of the cost curve.

- Natural Gas Lowers Many Pollutants Simultaneously. Natural gas use simultaneously reduces many pollutants (e.g., sulfur oxides, nitrogen oxides, reactive hydrocarbons, particulates, carbon monoxide, carbon dioxide). It produces virtually no SO_2 or particulate matter, about one-third as much NOx as coal, and one-half as much NOx as high sulfur residual oil. In addition, gas combustion produces no sludge or ash, in sharp contrast to the scrubbers and precipitators that are used to control emissions from coal.

- Natural Gas Can Increase the Use of Local Coal. Several of the current acid rain proposals have SO_2

emission limits that may be difficult and expensive to meet for units that burn high sulfur coal. One option is to employ a technique known as coal washing to partially reduce SO_2 emissions from the coal and then burn it with gas in a 30:70 gas:coal ratio. This technique reduces SO_2 emissions by two-thirds and preserves 70 percent of the market for high sulfur coal.

- Natural Gas Has Operating Advantages. Natural gas ameliorates operating problems caused by other control measures. For example, switching to low sulfur coal may cause substantial unit derating, while also increasing particulate emissions and solid waste disposal problems.

- Natural Gas Use Should Be Increased. Shortly after the NGPA was enacted, a natural gas deliverability surplus, or "bubble," developed in the United States. To the great surprise of many, this "bubble" grew rapidly and has persisted. Lower natural gas demand, coupled with supply stability, has led to 2.5 trillion cubic feet (Tcf) of shut-in U.S. gas. Furthermore, U.S. buyers have contracted for 1 Tcf of Canadian gas which they cannot take. This domestic and Canadian surplus has led to hardship among gas producers and to higher consumer prices because of take-or-pay prepayments for shut-in gas. The principal solution to both the take-or-pay problem and the decline in producer exploration is to sell more gas. More gas demand will alleviate take-or-pay for gas buyers and cause a "demand pull" for gas sellers that will put them back in the business of drilling for new supplies.

- Natural Gas Has Supply Security. Natural gas can displace foreign oil. For example, switching twelve New England power plants from oil to either natural gas or a gas/coal mix could reduce the region's use of imported oil by 15 percent, while improving the U.S. balance of payments.

- Natural Gas Use Creates Quick Sulfur Oxide Reductions. Most large oil burning units already have gas burning capability. Thus, substituting natural gas for high sulfur residual oil can reduce acid rain immediately, whereas other technologies require many years for equipment design, testing, and installation. For example, switching a large (750 megawatt) power plant from high sulfur oil to natural gas could reduce SO_2 emissions by 34,000 tons/year. As we mentioned above, this strategy has the added national security advantage of reducing imported oil demand by 7 million barrels/year.

(2) Gas Fired Combined Cycle and Cogeneration Units

States need not sacrifice economic growth to meet tougher emissions targets. New combined cycle and cogeneration plants can reduce the growth in the emissions inventory. A study by the Office of Technology Assessment, entitled "Acid Rain and Transported Air Pollutants: Implications for Public Policy" (June, 1984), predicts that total SO_2 emissions will increase by about .5 million tons to as much as 3.5 million tons by 2000, while NO_2 emissions will increase by as much as 5 million tons. This rate of increase could force states to require expensive retrofits for existing units and/or curtail growth from new construction. However, significantly lower emissions from combined cycle and cogeneration units make it possible to build new plants even with tougher emission standards.

Gas fired combined cycle and cogeneration units are two highly efficient and inherently low polluting ways to generate electricity. In a combined cycle unit the waste heat from a gas or oil turbine is recaptured and used to produce more electricity with a steam turbine. A cogeneration unit also produces electricity, but the waste heat is used on site in an industrial process. In either case, fuel, capital, and environmental costs are lower than for conventional coal-fired power plants. For example:

> A 240 MW electric power plant that uses 2 percent sulfur coal with a 10 percent ash content would produce 4000 tons of SO_2 annually and 200 tons of

> particulates, even with scrubbers and electrostatic precipitators. In contrast, the SO_2 and particulate emissions from a combined cycle unit are negligible (less than 0.3 percent of the coal unit) while NOx emissions are about half the coal unit's emissions. Cogeneration units have similar performance characteristics.

Unfortunately, the Fuel Use Act prohibits the construction of new gas-fired combined cycle and cogeneration units unless the owner first gets an exemption from the Department of Energy.4/ FUA and the other restraints on gas use force plant operators to turn to coal for new plants, even though natural gas units may be less expensive to build, easier to operate, and inherently less polluting than coal-fired units built with state-of-the-art control technology.

(3) Reburn Technology

Reburn technology is a NOx control method for coal-fired electric utility or industrial boilers, that plant operators can use on new or existing coal units to meet tougher NOx reduction standards. Again, FUA and the other demand restraints impede the use of this cost-effective technique.

In the reburn process, natural gas (or another fuel) is

4/ Even though the Department of Energy issues FUA exemptions, that process is so slow and expensive that many companies may be dissuaded from even applying. According to an A.G.A. survey of the exemption process, it takes from 6 months to 1 year for an exemption plus legal fees that may approach $100,000. Right now, the exemption process is delaying the sale of 225 billion cubic feet of gas, worth about $700 million/year in wellhead sales.

injected into the exhaust from a coal-fired boiler, creating a fuel-rich zone in which the NOx reacts and produces free nitrogen; air is then added to complete the combustion process. Because the gas is injected into the boiler before the heat exchanger, its energy is also used to generate steam. Preliminary testing indicates that gas reburn technology could reduce NO_2 emissions by 50 to 60 percent.

The Gas Research Institute (G.R.I.) has funded research by the Energy and Environmental Research Corporation that has shown that the technology works and that natural gas injection produces the largest NOx reductions. G.R.I. is currently planning to demonstrate this technology by retrofitting and testing an actual utility boiler.

CONCLUSION

Increased use natural gas by electric utilities and industrial energy users would result in substantial reductions in sulfur and other emissions levels. Furthermore, A.G.A. does not believe that the vast majority of the clean coal projects to be funded by the Clean Coal Technology Fund will be commercially available until well into the 1990s. This makes it imperative to repeal the FUA and other prohibitions on gas use, so that natural gas can be used in select use applications, combined cycle facilities and cogeneration, thereby helping to control air pollution and acid rain. A.G.A. thanks the Committee for allowing us to submit our views.

GRI

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DAVID O. WEBB
Senior Vice President,
Policy and Regulatory Affairs

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
JUN 06 1986
WASHINGTON, D.C. 20510

June 6, 1986

The Honorable James A. McClure, Chairman
Committee on Energy and Natural Resources
U.S. Senate
SD-361 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Mr. Chairman:

Gas Research Institute (GRI) appreciates the opportunity to submit testimony before the Energy and Natural Resources Committee pertaining to its review of the relationship between the DOE Clean Coal Technology Program and proposed strategies for acid rain control. GRI's testimony outlines its recent research results in a cost-shared program with the Environmental Protection Agency for natural gas use to enhance sulfur and nitrogen oxide emissions control in flue gases. GRI urges the committee to consider and recognize the role cost-effective emerging gas-enhanced emissions control technologies can play in using the nation's abundant coal resources in an environmentally acceptable manner. Any acid rain legislation should be sufficiently flexible to provide industry with the option to use emerging clean coal technologies.

If you should have any questions about GRI's testimony, I would be glad to answer them.

Sincerely,

David O. Webb

David O. Webb

Attachment
cc: Richard D. Grundy
Jeffrey Arnold

Gas Research Institute, 8600 West Bryn Mawr Avenue, Chicago, Illinois 60631 312/399-8100

TESTIMONY OF DAVID O. WEBB
SENIOR VICE PRESIDENT, POLICY AND REGULATORY AFFAIRS
BEFORE THE ENERGY AND NATURAL RESOURCES COMMITTEE
U.S. SENATE
JUNE 9, 1986

I appreciate the opportunity to submit testimony today that outlines the Gas Research Institute's (GRI) recent research results on the use of natural gas to enhance cleanup of sulfur oxide (SO_x) and nitrogen oxide (NO_x) emissions from flue gases. Gas-enhanced emission control is one of the most promising near-term clean coal technologies, especially for retrofitting existing coal-fired boilers. It is critical for this committee to understand the potential of and time frame for commercializing emerging gas-enhanced clean coal technologies to reduce SO_2 and NO_x emissions when it considers the relationship of proposed acid rain legislation and the DOE Clean Coal Technology Program. Otherwise, the committee might not be aware of these promising technologies and may inadvertently exclude their use in the legislation by establishing unrealistic compliance dates or by specifying the technology.

Congress has assigned a high priority to providing technology options for using our nation's abundant coal resources in an environmentally acceptable manner. Last year despite administration objections, Congress approved legislation appropriating $400 million for the Department of Energy (DOE) to demonstrate clean coal technologies through a cofunded program with industry. The private sector's response to DOE's request for statements of interest in demonstrating clean coal technologies clearly emphasizes the potential role of gas in clean coal technologies. Within the 176 private sector responses, the two largest technology categories were flue-gas cleanup (31 responses) and surface coal gasification (27 responses). In testimony last year before congressional committees on the clean coal program, DOE emphasized that the primary goal of emerging flue-gas cleanup technology is to provide low-cost approaches to NO_x and SO_2 emissions reduction at existing power plants. Therefore, it is encouraging that about one-fourth of the 51 proposals submitted to DOE in response to the Clean Coal RFP will use retrofit technologies to reduce SO_2 and NO_x emissions. Several of the proposals use gas in these applications. This is important since applications that use natural gas in combination with other technologies for flue-gas cleanup have the potential to provide one of the most cost-effective methods to use coal in existing utility and industrial boilers. Therefore, in the near term, the use of gas to enhance emissions control is an essential element of emerging integrated flue-gas cleanup systems. These systems offer the potential for early retrofit in many utility and large industrial boilers once they have been demonstrated on a full scale in operational utility systems.

Legislation must be sufficiently flexible to allow the introduction of emerging cost-effective gas-enhanced and other clean coal technologies as an option for industry in reducing NO_x and SO_2 emissions. Legislation that predetermines the technology options or establishes very near-term compliance schedules severely limits industry's ability to meet new emission standards and in many applications precludes the most cost-effective solutions, especially those that will be demonstrated under the DOE Clean Coal Technology Program. GRI urges the committee to consider these factors when it considers any acid rain legislation. Industry should not be limited in its use of natural gas in combination with other emerging clean coal technologies to produce the best and most cost-effective solutions.

GRI is an independent, not-for-profit scientific research organization that plans, manages, and develops financing for a cooperative research and development program for the mutual benefit of the gas industry and its present and future customers. The R&D program is implemented through contracts with research organizations, engineering and other professional service firms, universities, energy companies, and manufacturers.

Even though GRI is not a government contractor and does not accept federal funds, GRI cofunds and coordinates many of its research programs with DOE and other federal agencies including the Environmental Protection Agency (EPA). Over the last two years, GRI has cofunded research with the EPA on the use of gas to control NO_x emissions from coal. The results of this technology, generally referred to as "gas reburn," are very promising. Recently, GRI has agreed to provide cofunding for EPA's planned field demonstration of reburn technology which will be combined with sorbent injection technology to reduce SO_2 and NO_x emissions simultaneously. Also, GRI has pledged cofunding for a proposal submitted under the DOE Clean Coal RFP to demonstrate these gas-enhanced emissions control technologies. Three utilities will participate in this demonstration starting in early 1987. If the results obtained in laboratory tests can be demonstrated successfully as a retrofit technology for industrial and utility boilers during the next two to three years, this technology would provide industry with an extremely cost-effective solution for combining NO_x and SO_2 emissions reduction. For this reason, I am submitting this testimony to make the committee members aware of these emerging technology options.

THE IMPORTANCE OF EMERGING TECHNOLOGIES

On April 24, 1984, the Secretary of DOE asked the Energy Research Advisory Board (ERAB) to convene a panel to assess the principal technologies for the clean use of coal. The ERAB panel completed its assessment in 1985. The committee should be aware of several of the panel's findings in its debate on any new legislation to reduce emissions from coal. These findings are:

1. Coal use in the U.S. is expected to continue to increase for most of the next 25 years.

2. The two major factors influencing this trend are the low price of coal compared with other fuels and the reduced contribution of nuclear power.

3. The number of specific coal-use situations is so large and diverse, and the specific problems are so site-specific that no generally applicable solution can be presented. This issue is even more difficult when applied to retrofit situations which represent the overwhelming majority of applications.

4. Direct combustion of coal will continue to represent over 90 percent of all coal use for the rest of the century and beyond.

5. Greater cooperation, particularly between DOE and EPA, and more coordinated funding can speed up completion of R&D programs that are urgently needed.

The ERAB panel made four specific recommendations in its report to DOE that clearly indicate the importance it assigns to emerging clean coal technologies.

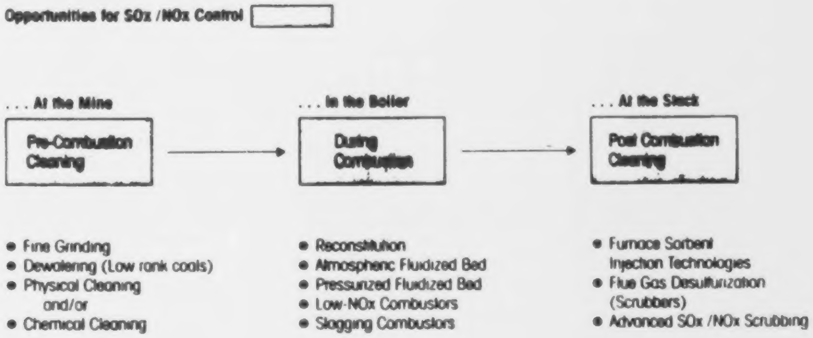
1. Early demonstration of retrofit technology is most urgent.

2. Limestone Injection Multistage Burner (LIMB) and improved Flue-Gas Desulfurization (FGD) should be top priorities. Aggressive pursuit of this target will make full deployment possible around 1990.

3. It is important to make sure that the high-sulfur coals that can be mined at a relatively low cost are given priority for the test work. This includes coals from areas such as Illinois and Indiana Nos. 5 and 6 seams, Kentucky Nos. 9 and 11 seams, and Ohio and West Virginia Pittsburgh seams.

4. The basic goal of the research will not be achieved unless we can apply new processes to the high-sulfur coals.

CHART 5
Coal Utilization


Opportunities for SOx /NOx Control
. . . At the Mine
Pre-Combustion Cleaning
. . . In the Boiler
During Combustion
. . . At the Stack
Post Combustion Cleaning
• Fine Grinding
• Dewatering (Low rank coals)
• Physical Cleaning and/or
• Chemical Cleaning
• Reconstitution
• Atmospheric Fluidized Bed
• Pressurized Fluidized Bed
• Low-NOx Combustors
• Slagging Combustors
• Furnace Sorbent Injection Technologies
• Flue Gas Desulfurization (Scrubbers)
• Advanced SOx /NOx Scrubbing

(Integrated Gasification Combined Cycle and Magnetohydrodynamics offer similar SOx /NOx control opportunities with differing techniques.)

ROLE OF GAS IN CLEAN COAL TECHNOLOGIES

Federal policy has long overlooked the significant role natural gas can play in helping the nation use coal in an environmentally acceptable manner. Therefore, it is particularly encouraging to GRI and the gas industry that ERAB emphasized the urgency to demonstrate flue-gas cleanup for both NO_x control and to assist in SO_2 control in its report to DOE. In fact, for many near-term retrofit applications, gas used in combination with coal in both industrial and utility combustion systems has the potential to be the most cost-effective solution.

Natural gas is our nation's cleanest fossil fuel. Its combustion emits virtually no particulates, sulfur oxides, or reactive hydrocarbons, and it produces far lower emissions of nitrogen oxides and carbon monoxide per unit of energy than coal or oil. Gas is a domestic resource, and the gas supply outlook is excellent. The price of gas is attractive, and because users do not have to worry about onsite storage, the operating and maintenance costs are also lower. Used selectively, either alone or with other more polluting fuels, relatively small quantities of natural gas could contribute significantly to protecting our air quality in a least-cost manner. Given these factors, the competitive position of gas relative to other environmental control options should remain favorable. In addition, a million-mile pipeline and distribution network is already in place which extends to most utility and large industrial customers. Therefore, pollution control technology using gas can begin almost immediately.

Gas can be used in one combustion unit to offset the emissions from dirtier fuels, such as coal, in another unit; it can be used for simultaneous combustion of gas and coal in a single combustor; and it can be used to enhance flue-gas cleanup systems, particularly sorbent injection techniques to reduce SO_2 and in a reburn mode to reduce NO_x. Only natural gas offers this ability for one control technology to reduce several pollutants at the same time. Therefore, using gas as part of the overall approach to controlling pollutant emissions during coal combustion should become one central element of national energy policy.

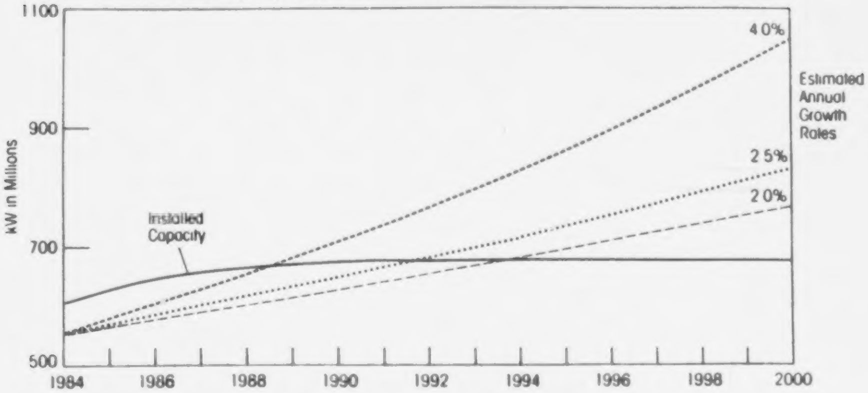
U.S. FUELS OUTLOOK

Another policy factor to consider in determining the importance of adopting flexible legislation standards and compliance deadlines that would allow emerging clean coal technologies to reduce industrial and utility boiler emissions is the extent to which the U.S. must rely on coal to meet its electric power generation demands between now and 2010. As a result of several major independent trends, the use of coal in the U.S. is expected to continue to increase at a reasonably steady pace for most of the next 25 years. The major influences of this trend are the continued economic advantage of coal compared with other fuels, its abundant supply, and the reduced contribution of nuclear power.

However, unless technology is demonstrated and introduced into the market to allow the U.S. to utilize its coal in an environmentally acceptable manner, the U.S. faces the possibility of regional shortage in electric generating capacity in the 1990s. The extent and timing of any specific shortages is very difficult to predict. Economic forecasts contained in DOE's National Energy Plans (NEP) have shifted from 4-percent-per-year growth in the economy in early 1970s NEPs to almost no growth forecasted in the NEPs issued in the late 1970s to about 2-percent-per-year growth in NEPs released in the early 1980s. To further complicate any projections, during the past decade, actual electricity growth has ranged from an increase of 7 percent per year to only 1.8 percent growth in 1985.

However, under any reasonable scenario of growth, electric consumption will increase. As stated by DOE Secretary Herrington in a speech on April 23, 1985, "Demand for electric power has continued to show a strong relationship with the growth of our economy." GRI's own modeling efforts indicate future electricity growth will be at a rate equal to approximately 85 percent of the rate of the economy's growth. Therefore, unless our economy is totally stagnant with resulting rapid increases in unemployment and misallocation of resources, electricity demand in the 1990s will continue to increase and will require the construction of new generating plants.

U.S. Electric Generating Capacity and Peak Demand, 1984-2000



Note: Peak demand at stated growth rates with 20% capacity margin needed for dependable supply. Includes existing capacity and capacity under construction less retirements of 15 million kilowatts through 1993 as reported to NERC.

If nuclear power does not make a quick resurgence to survive as a viable future U.S. energy option, coal is the major domestic energy option with sufficient long-term resources to fuel the majority of these power plants. This scenario becomes especially convincing when you consider that the U.S. holds one-quarter of the world's known coal reserves, and electricity use, even with all of the conservation due to higher energy prices and economic downturns, has grown by approximately 30 percent since 1973.

If there is one thing the energy crisis of the past 12 years has taught us, it is that uncertainty is the only certainty. Long-term energy forecasts have proven to be consistently wrong. We cannot make policy assumptions with any confidence regarding the direction of energy demand, production, and prices. The real interest rates are double the historical experience. Also, it must be recognized that the economics of many emerging energy technologies are driven by the price of world oil, and this price is not based on production costs. In other words, the typical utility executive must make major energy decisions in a very unstable and uncertain operating environment.

In this environment, the utility sector must not be restrained in choosing the technology options best suited to cost-effective emissions reduction. All technology options--including gas-enhanced coal combustion and flue-gas cleanup--must be available. If any legislation is passed, it can be cost-effective only if it provides the flexibility to allow the select use of gas and emerging clean coal technologies to be choices available to industry.

GAS-ENHANCED DRY SORBENT INJECTION AND REBURN

Concern over acid precipitation and anticipated acid deposition legislation has created an incentive for government and industry to develop more cost-effective technologies to control both sulfur and nitrogen oxides from coal and oil combustion, particularly from utility and large industrial boilers.

GRI and the EPA have been funding the Energy and Environmental Research Corporation (EERC) of Irvine, California, to develop reburn and dry sorbent injection technology to control SO_2 and NO_x emissions from coal and oil combustion. GRI's focus has been to examine control of NO_x and SO_2 emissions from coal combustion by incorporating two developing gas combustion technologies which can be applied individually or as an integrated element of a flue-gas cleanup system.

1. Reburn Technology. Use of natural gas as a reburning fuel to reduce NO_x emissions.

2. Sorbent Injection Technology. Use of natural gas to improve the capture efficiency of reactive sorbents for enhanced SO_x reduction.

EPA provided $860,000 ($400,000 in FY 1983 and $460,000 in FY 1984) in coordinated funding for the project via its existing reburn/sorbent injection contract with EERC. GRI's project ($937,900), which began in April 1984, expands EPA's original focus on coal-fired reburning/sorbent injection at EERC to include an evaluation of the additional benefits (e.g., cost reduction, increased emissions control, boiler operation improvements, etc.) obtainable from the use of gas.

Sulfur oxides can be controlled by removing sulfur from the fuel or sulfur oxides from the products of combustion. However, current methods such as scrubbers or coal cleaning generally are capital intensive with high operating and maintenance costs, or they do not provide the necessary degree of SO_x control.

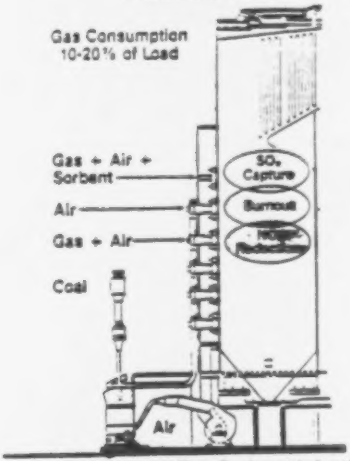
One of the more promising SO_x control strategies is to inject calcium-based sorbents into the combustion chamber to capture the sulfur prior to the boiler outlet. This process was investigated in the late 1960s and was abandoned because it could not achieve the desired SO_x control and also tended to create operational problems. Recently, there has been sufficient incentive to reexamine the limestone injection process (e.g., LIMB) as a cost-effective retrofit alternative for acid rain precursor control. The EPA's efforts in recent years have focused on the development of this technology for coal-fired boilers.

GRI's program with EERC has been to enhance the cost-effectiveness of this technology through the use of gas combustion technology. Gas may offer improved sorbent injection performance benefits by more effectively controlling the conditions at which limestone sorbent is calcined and mixed with the coal combustion flue gases; it may help to avoid coal-ash/sorbent interaction problems that decrease sorbent surface area; it can be used more effectively to optimize the temperature profile of the sulfation zone where sulfur capture occurs; and it reduces the amount of sorbent material needed.

Nitrogen oxide emissions are also considered, although historically to a lesser extent, as a contributing factor to acid deposition. The attention to NO_x as an acid deposition processor is increasing as scientific evidence tends to indicate that both SO_x and NO_x are contributors. The formation of NO_x during the combustion of fossil fuels can be minimized by appropriate modification of the combustion process.

Recently, the Japanese have introduced a new NO_x control strategy which involves in-furnace NO_x reduction by creating a transient reducing zone within the boiler. EPA has been conducting research programs to evaluate the potential of this technique for application to U.S. boilers. The term "reburning" has been coined in the U.S. to refer to this process. When using gas as the reburn fuel, it appears that this technology is capable of reducing NO_x by approximately 50 to 60 percent beyond a boiler's current emission levels. The use of coal or oil as a reburning fuel may introduce operational problems because of poor carbon burnout resulting in a loss of efficiency as well as slagging in the platens or primary superheater region. The specific technical benefits of using gas as the reburning fuel are that gas can be broadly retrofitted to existing boilers and can be applied without the combustion problems associated with coal firing in upper boiler regions; gas allows lower exhaust NO_x emission levels to be achieved since it is nitrogen free; and gas avoids the presence of molten ash in the superheater boiler region, thereby minimizing slagging and fouling problems.

GAS APPLICATIONS RESEARCH



Gas Enhanced Dry Sorbent Injection Plus Gas Reburn – SO_2/NO_x – Control

The use of gas technologies could also have an application in those instances where oil-fired boilers are being converted to coal-water slurry mixtures. Combustion systems which burn coal water slurries efficiently in boilers designed for oil rely upon efficient fuel-air mixing, precisely those conditions which promote the formation of nitrogen oxides. Consequently, any conversion could result in a considerable increase in both SO_x and NO_x

emissions. An additional problem associated with conversion to coal-water slurries is the need to derate the unit to prevent excessive erosion in the convective sections. In some cases there are operational problems from unstable ignition. Natural gas used as a reburning fuel with or without sorbent injection can help solve these problems--pollutant emissions, unit derating, and flame stability.

Potential benefits of gas use are both environmental and economic. The development of more cost-effective SO_x, NO_x and combined SO_x/NO_x control technologies using gas would lower energy costs and improve air quality. The economic benefits are broad based and provide an alternative to high-cost flue-gas scrubbing technologies. In addition to the significant NO_x and SO_x reductions, boiler operators may also realize substantial operating benefits (mitigation of boiler derating, particulate control, and reduction of availability problems, etc.) by implementing gas-enhanced reburn/sorbent injection techniques. Furthermore, the gas-enhanced technologies would increase our ability to use the nation's natural resources and would decrease our dependency on imported oil. The environmental payoff is a significantly reduced quantity of pollutants emitted by coal or oil burning.

Specific elements of the joint EPA/GRI research program that GRI funds are detailed on the following pages.

GAS REBURN--NO_x CONTROL

1. GRI's initial research goal is to develop gas reburn technology for NO_x control and to integrate gas reburn and boiler sorbent injection technologies for combined NO_x and SO_x control.

2. The reburn research focus is to determine the optimum conditions and gas injection techniques to create fuel rich reburn regions for NO_x reduction.

3. Coal is burned as the primary fuel in the lower portion of the boiler under conventional conditions with the reburn gas (10 to 20 percent of total boiler fuel input) and, burnout air is injected in the higher sections of the boiler.

4. Research results to date from pilot scale testing indicate that NO_x emissions can be reduced significantly (greater than 50 percent) when small amounts of gas are fired in reburn fashion.

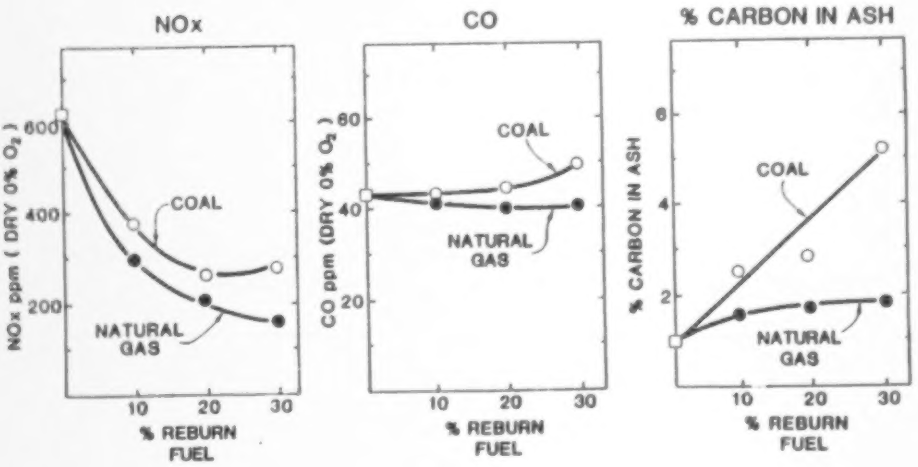
5. Compared to coal as the reburn fuel, gas is more effective in NO_x reduction; requires shorter reaction time; does not present operational problems such as carbon burnout, slagging, etc.; and simultaneously reduces SO_x and particulate matter.

6. In addition to lower NO_x levels, gas reburn may be easier to retrofit than low-NO_x burners. For some boiler configurations low-NO_x burners are not commercially available.

The advantages of gas versus coal as a reburn fuel are illustrated below.

COMPARISON OF THE EFFECTIVENESS OF GAS
AND COAL AS REBURN FUELS.

(PRIMARY FUEL : COAL ; SCALE : 10×10^6 Btu/hr)



GAS-ENHANCED DRY SORBENT INJECTION--SO_x

1. Simultaneously, GRI is funding research to use natural gas to enhance SO_x control. This research is focused on both combining reburn technology with sorbent injection where there is a SO_x reduction proportional to the amount of gas reburn fuel used and developing gas-enhanced sorbent preparation and injection techniques where gas is used to increase sorbent reactivity and utilization.

2. If successful, GRI's research will improve the cost-effectiveness of LIMB by reducing sorbent expenses and increasing SO_2 capture. More importantly, use of gas will lower the solids loading within the boiler and particulate control system.

3. Critical technical issues regarding sorbent injection are the quantity of sorbent material in boiler convective sections and entering electrostatic precipitators, calcination of sorbent to maximize surface area, protection of sorbent from sintering, and rapid mixing of sorbent with coal combustion flue gases within the temperature window (1750° to 2250°) for SO_2 capture.

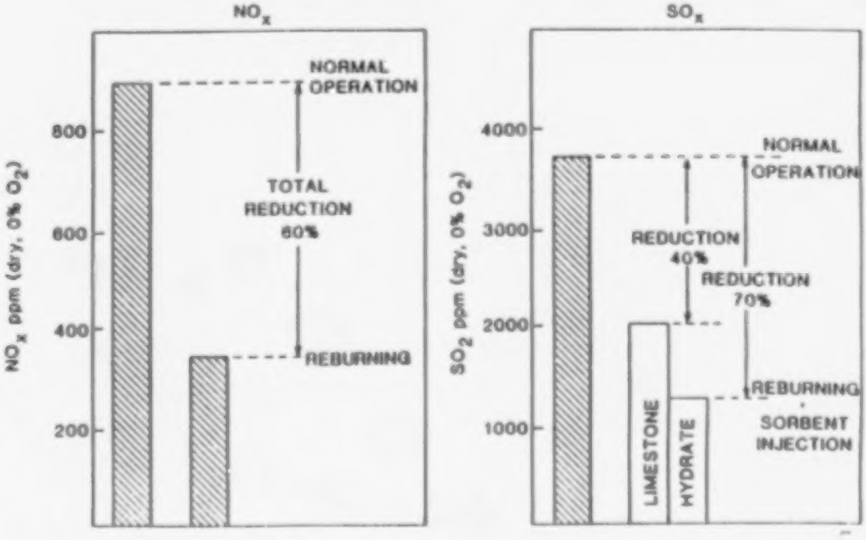
4. The relatively uniform composition and ease of handling makes natural gas the ideal fuel for resolving the critical technical issues and for enhancing the effectiveness of SO_x removal.

5. Potential benefits of this research would be an improvement in the cost-effectiveness of LIMB technology and potentially broader applicability.

6. Total gas fuel requirements for combined gas-enhanced reburn and sorbent injection technologies are estimated to range from 15 to 20 percent of the total boiler fuel input.

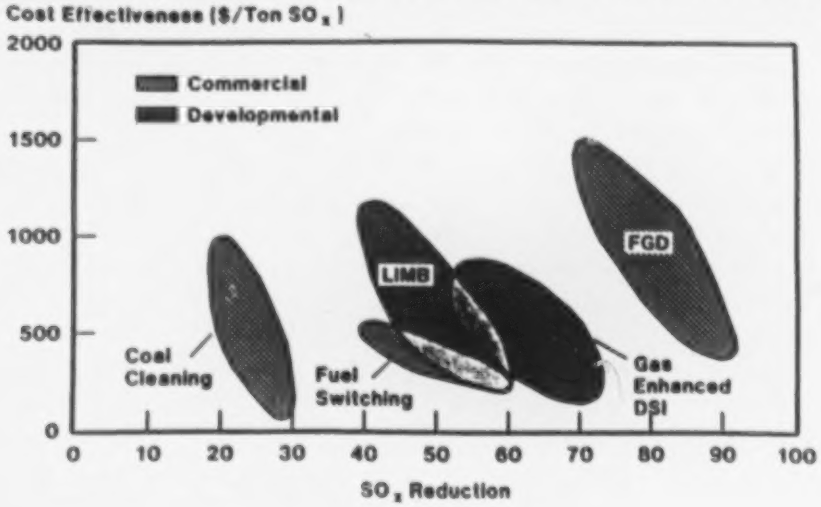
An illustration of the effectiveness of using natural gas to enhance flue-gas cleanup options is shown below.

GAS REBURNING-SORBENT INJECTION EFFECTIVENESS PRE-NSPS BOILER FIRING HIGH SULFUR COAL



The following figure is a graphic display of the range of DOE and EPA cost-effectiveness data available from the literature for each technology. The figure also shows the improved performance goals for gas-enhanced Dry Sorbent Injection (DSI) technology relative to LIMB. Of the technologies considered in the figure, only LIMB with low-NO_x burners and gas-enhanced DSI plus gas reburn provide for both SO_x and NO_x control. Gas reburn achieves lower NO_x levels. The basis for these cost comparisons are presented in the attached Tables 1 and 2.

RELATIVE COST EFFECTIVENESS OF ALTERNATIVE ACID PRECURSOR CONTROL STRATEGIES - SO_X



In conclusion, gas has the unique advantage of allowing the simultaneous application of reburn and sorbent injection technologies in the same boiler. GRI plans to commit $10 million over the next four years to cofund a demonstration of these gas-enhanced emissions control technologies in three operational utility boilers. The program, which the Energy and Environmental Research Corporation proposed in response to the DOE Clean Coal RFP, would demonstrate these gas technologies in the three primary boiler configurations the utilities use: sidewall-fired boiler, tangentially-fired boiler, and cyclone-fired boiler. The proposed program would start on January 1, 1987, and would cost $30 million over the four-year demonstration.

By using natural gas to enhance reburn/sorbent injection technology, GRI's goal is to provide greater than 50 percent NO_x and 50 percent SO_2 emissions reduction while offering cost advantages over competing wet-scrubbing technology. These proposed demonstrations, if successful, would provide the electric utility and industrial boiler market with a cost-effective retrofit technology in the early 1990s.

CONCLUSION

Emerging clean coal technologies that use gas, especially gas-enhanced combustion techniques to reduce SO_2 and NO_x emissions from flue gas, offer the potential to provide cost-effective solutions to reducing emissions from coal. In bench-scale tests, the addition of 15 percent natural gas to enhance the combustion of coal and to increase the effectiveness of sorbent injection has resulted in NO_x and SO_2 reductions of 50 percent. The next step is to demonstrate the technology in utility and industrial boilers. This could lead to commercialization in the early 1990s. Therefore, any legislation that mandates reductions in emissions of SO_2 and NO_x from coal must contain the necessary flexibility to provide industry with the opportunity to use these emerging technologies. Without this option, years of federal and industry research efforts and federal research funding will be wasted. More importantly, the most cost-effective solutions will not be available as options to industry. This will result in the increased cost of electricity for all consumers.

Mr. Chairman, that completes my testimony. I sincerely appreciate the opportunity to submit this statement to your committee.

Table 1

BASES FOR ECONOMIC COMPARISONS OF SO_x and SO_x/NO_x RETROFIT CONTROL TECHNOLOGIES FOR POWER PLANTS

500 MW Rated Capacity -- Wall-Fired Boiler
Capacity Factor = 0.6
Coal Characterisitcs: 2.5% Sulfur
12.5% Ash
11,500 Btu/lb
15-Year Levelization Period
Flue Gas Desulfurization at 90% SO_x Removal
Natural Gas Reburn/Dry Sorbent Injection at 60% NO_x and 50% SO_x Control
15% Gas of Total Boiler Fuel
s Fuel Price Premiums of $1 and $2 per Million BTU Compared to Coal
I Cost Guidelines
6 Dollars

Table 2

COMPARISON OF COSTS OF SO_x and SO_x/NO_x RETROFIT CONTROL TECHNOLOGIES FOR 500 MW WALL-FIRED BOILER

	Investment Cost		Levelized Annual Cost		Emission Reduction			
					1000 Tons/Yr		Cost, $/Ton	
	$Million	$/KW	$Million/Yr	Mills/KWH	SO_x	NO_x	SO_x	SO_x/NO_x
Flue Gas Desulfurization	108	216	43	16	50	0	860	860
Natural Gas Reburn/ Dry Sorbent Injection								
$2/Million BTU Premium	24	48	26	10	28	7	925	740
$1/Million BTU Premium	22	45	21	8	28	7	750	600

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S R. ENGLISH
CITY ATTORNEY

TELEPHONE
904/599-8100

May 30, 1986

The Honorable James A. McClure
United States Senate
The Dirksen Building
SD-361
Washington, D.C. 20510

Dear Senator McClure:

SUBJECT: Support for the City of Tallahassee, Florida
Clean Coal Technology Demonstration Project

The City of Tallahassee, Florida, submitted a proposal to the Department of Energy during April, 1986, to conduct a cost-shared clean coal technology demonstration. That proposal was a response to Program Opportunity Notice Number DE-PS01-86FE60966 issued in accordance with the requirements of Public Law No. 99-190 which provides funds for such projects.

The City proposes to construct a 235-MW circulating fluidized bed combustor (CFBC) at an existing electric power plant site. The conventional boiler currently in use at the plant site uses oil and/or natural gas fuel. The proposed CFBC unit would be capable of burning various qualities of coal (including high ash and high sulfur coal typical of midwestern or eastern resources) while controlling acid gas emissions to the atmosphere. A cost share of $50 million has been requested from DOE for the proposed demonstration project which has a total estimated cost of $300 million.

Once demonstrated at the proposed size, which is appropriate for electric utility applications, CFBC technology could be proven and a primary objective of the DOE Clean Coal Technology Program would be satisfied. CFBC could then be used in new or retrofit situations and could provide a viable alternative for reduction of acid gas emissions. CFBC units could use coal more cleanly, efficiently, and economically than conventional coal-fueled boilers.

"FLORIDA'S CAPITAL CITY" — SERVING ALL FLORIDA

The City requests your support of the Clean Coal Technology Program in general and the City's proposal to DOE in particular. The enclosed brochure addresses key aspects of the proposed project, CFBC technology, demonstration project economics, and environmental advantages. Please take a few minutes to read through it. If you have any quetions, please contact:

Mr. A. K. (Ben) Sharma
Superintendent of Planning
and Engineering
Electric Department
City Hall
300 Adams Street
Tallahassee, Florida 32301

or telephone (904) 599-8504.

Sincerely,

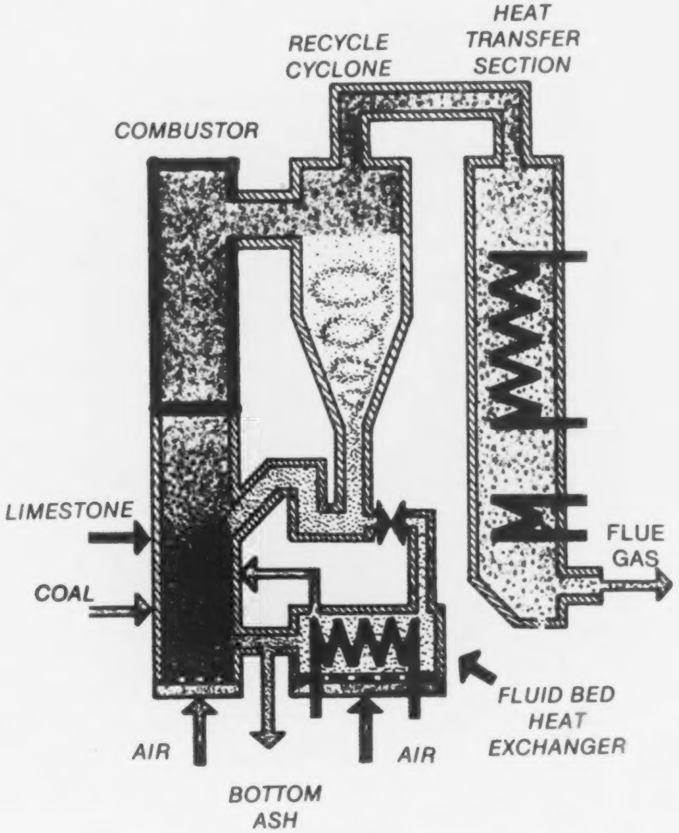
CITY OF TALLAHASSEE, FLORIDA

Jack L. McLean, Jr.
Mayor

JLM/RTK:mgm

Enclosure

City of Tallahassee, Florida Proposed Clean Coal Technology Project For The Department of Energy



THE PROJECT

Q. What has the City of Tallahassee (City) proposed?

The City has proposed to construct a 235-MW circulating fluidized bed combustor (CFBC) at Arvah B. Hopkins Station to power a turbine generator currently receiving steam from an existing boiler fueled by gas or oil. The City has requested a $50 million cost share from the Department of Energy (DOE).

Q. Why did the City submit a proposal to DOE?

As a follow-up to recommendations of DOE's 1983 report, Conversion of Florida Electric Power Plants from Oil to Coal Fuel, the City reviewed its power supply needs and investigated conversion of various of its generating units to coal fuel to reduce its dependency on oil and gas. Cost sharing under the Clean Coal Technology Program is considered attractive because the DOE cost share would largely offset the risk of using such a new technology as well as the additional costs incurred in documenting a demonstration project, and the City is prepared to meet all the requirements of the DOE Program Opportunity Notice.

Q. How extensive are the proposed modifications of Arvah B. Hopkins Station?

The project primarily would involve construction of a CFBC unit and coal handling equipment. The existing turbine generator and the balance of the plant facilities would be used in conjunction with the CFBC.

Q. What is the significance of the project at local and national levels?

The proposed project would reduce the City's current dependency on oil and gas fuels while reducing potential acid gas emissions. It would also provide the direct and indirect socioeconomic benefits to northwest Florida of a $300 million project. At the same time, it would be a major technological advance to demonstrate that the CFBC technology can be designed and operated at a size (235 MW) appropriate for utility use. Such a demonstration is needed before U.S. generating utilities will use the technology and realize the economic and environmental advantages of CFBC in comparison to conventional coal units.

CIRCULATING FLUIDIZED BED COMBUSTOR TECHNOLOGY

Q. **What is CFBC?**

Combustion in a fluidized bed is accomplished by mixing fuel with hot solid particles (usually limestone) suspended in an upward air flow. In a CFBC unit, most of the bed particles suspended in the flue gas are removed at the top of the combustor and recycled to the bottom to replenish the bed.

Q. **What are the advantages of CFBC over conventional coal combustion?**

There are five major advantages associated with the use of CFBC systems. Those advantages include the following:

1.) A variety of fuels can be burned including inexpensive low-grade fuels with high ash and high sulfur content.

2.) Various materials can be used as the fluid bed medium, thereby serving not only as a combustion medium but also efficiently removing sulfur compounds by reaction with the bed material during combustion.

3.) The relatively low combustion temperatures avoid softening of coal ash, thus producing ash which is low in siliceous glass, eliminating slagging and fouling problems.

4.) Maintaining low combustion temperatures also inhibits the formation of nitrogen oxides.

5.) The solid waste consisting of bottom ash, fly ash, and reaction products forms a dry solid with advantageous physical and chemical characteristics.

Q. **What is the potential for use of CFBC in the electric utility industry?**

CFBC is an attractive alternative for utilities because new or retrofit units can be operated economically, efficiently, and with minimal environmental effect. The fuel flexibility, high combustion efficiency, and minimal operating problems are the key attributes for utility consideration. Based on DOE projections of growth and expected market penetration, demonstration of a 235-MW unit (a size popular in current utility planning) could lead to as much as 41,000 MW of CFBC generation being constructed by the year 2010.

ENVIRONMENTAL ADVANTAGES

Q. **Could CFBC technology reduce the impacts of acid rain?**

Yes, acid gas emissions associated with CFBC units would be expected to be significantly lower than emissions from conventional coal-fueled units. By the year 2010, the advent of CFBC (41,000 MW) could result in sulfur dioxide emission reductions of 678,900 tons per year and nitrogen oxides emissions reductions of 363,175 tons per year.

Q. **How is sulfur removal accomplished without flue gas desulfurization (FGD) equipment?**

A fluid bed medium (such as limestone) is used which absorbs sulfur compounds during the combustion process. A portion of the bed medium, primarily fly ash, is constantly removed during operation.

Q. **How are nitrogen oxides emissions controlled?**

The CFBC process allows operation at lower combustion temperatures than conventional units. Nitrogen oxides formation is inhibited at such lower temperatures.

Q. **What other environmental advantages are expected?**

The sulfur removal method, low combustion temperatures, and high combustion efficiency characteristic of CFBC units result in solid wastes which are physically and chemically more amenable to land disposal than the solid wastes resulting from conventional coal burning boilers with FGD, including those using sludge stabilization methods.

Q. **What are the regional and national implications of CFBC fuel use capabilities?**

CFBC units can burn a wide variety of fuels including high ash and/or high sulfur coal efficiently without emissions problems. This fact should lead to general socioeconomic benefits because substantial midwestern and eastern coal reserves which are unacceptable for conventional units could be marketed for CFBC units. Assuming 41,000 MW of new CFBC generation by 2010, consumption of such coal by CFBC units could exceed 182 million tons per year.

PROJECT ECONOMICS

Q. What is the projected total cost of the proposed project?

The total estimated cost is $300,920,000 (1991 dollars) including slightly more than $83,320,000 for the cost of issuing bonds, debt service, and interest.

Q. How much of a cost share has been requested from DOE?

A cost share of $50 million has been requested.

Q. How do the capital and operating costs of a CFBC unit compare with a conventional 235-MW, coal-fueled boiler?

This question will be addressed as part of the demonstration project. Based on data from small CFBC units, however, it appears that capital costs may be comparable and that operating costs of a CFBC unit would likely be lower.

Q. What is the basis for the expected operating cost advantages of CFBC over a conventional coal-fueled boiler?

Operating cost advantages of a CFBC would be derived from fuel costs and from various operating efficiencies.

Fuel costs are a major consideration of the operating costs of a generating facility. Those costs are affected by the cost of the raw fuel, transportation to the facility, fuel preparation, and coal cleaning and/or FGD to meet emissions requirements. The capability of CFBC to burn a variety of fuels in an environmentally acceptable manner would allow a utility to negotiate for fuel based on total cost with minimum regard to fuel specifications. This could promote the use of regional coal reserves, reducing transportation costs while minimizing the cost of emission control.

There are several operating efficiencies associated with CFBC units. Fuel preparation costs are reduced since washing and pulverizing are not necessary. In addition, slagging and fouling problems are essentially eliminated by the lower operating temperatures in a CFBC. Environmental compliance costs are also reduced because of the lack of FGD equipment and advantageous characteristics of solid wastes.

The Electric Department of the City of Tallahassee, Florida operates generating and transmission facilities serving approximately 140,000 people in the city and surrounding Leon County. The proposed project would reduce the city's dependency on oil and gas fuels by converting its largest generating unit to coal fuel capability. Consequently, substantial reductions of local acid gas emissions could be realized in comparison to the permitted emissions associated with oil fuel.

The City of Tallahassee has submitted a proposal to the Department of Energy under the Clean Coal Technology Program because it recognizes potential advantages for itself, the electric utility industry, and the nation. A cost share has been requested from the Department of Energy which is commensurate with the additional effort associated with documenting a demonstration project and the possible risks to Tallahassee of applying such a new technology.

The City of Tallahassee has assembled a project team consisting of nationally recognized firms with fluidized bed combustion experience. The project team includes:

- City of Tallahassee
  (owner and project manager)
- Combustion Engineering/Lurgi
  (CFBC boiler technology consultant)
- Bechtel North American Power Corp.
  (architect/engineer)
- Westinghouse Electric Corp.
  (turbine consultant)
- R. W. Beck and Associates
  (financing/environmental engineer)

Please address any comments or questions about this project to Mr. A. K. Sharma, Superintendent of Planning and Engineering, City Hall, 300 Adams Street, Tallahassee, Florida 32301. Mr. Sharma may be reached by telephone at (904) 599-8504.